COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

ANNUAL REPORT, 2003

(REDACTED VERSION)

D.T.E. 01-67

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

JANUARY, 2004

ATTACHMENTS:

I. INTRODUCTION

FG&E hereby files its Annual Report in compliance with the directives of the Department in D.T.E. 01-67 and D.T.E. 98-84/EFSB 98-5. In particular, FG&E responds to the six specific areas that the Department identified as matters to be addressed as part of the Annual Report:

A. ten-year peak demand forecasts for the distribution company's service area;
B. planning criteria and guidelines for the distribution system planning process;
C. an operating study showing power flows and voltages under normal and emergency conditions;
D. listing of critical loads by towns and the circuits by which they are fed;
E. a listing of significant reliability and infrastructure improvement projects planned for construction within the next five years; and
F. a prioritization of future projects.[1]

II. REPORT LAYOUT

A. TEN-YEAR PEAK DEMAND FORECASTS

Ten-year summer and winter peak demand forecasts for the FG&E electric system are provided in Appendix D (page D.2) of the *FG&E Electric System Planning Study 2004-2013* dated August 12, 2003 (see Attachment 1). This portion of the document describes the methodology used to develop "peak design load" and "extreme peak load."

---

[1] **Please note that this filing, though structured differently than FG&E's previous Annual Report in this docket, filed in January 2003, covers each of these six areas and contains all of the required sections. This introduction provides an overview and location of each section within the Report.**

Load forecasts for the distribution system are developed on the circuit level and the load is forecasted for 5 years. The methodology used to develop the summer and winter peak demand forecasts for the FG&E distribution system can be seen in Section 4 of the *FG&E Distribution System Planning Evaluation 2004-2008* dated August 8, 2003 (see Attachment 2). A circuit-by-circuit tabular listing of the summer and winter peak demand forecasts are in Appendix A of Attachment 2.

B. PLANNING CRITERIA AND GUIDELINES FOR ENTIRE DISTRIBUTION SYSTEM PLANNING PROCESS

FG&E utilizes a variety of references in its system planning process. The various references include Company guidelines for electric system planning and design; applicable Company construction standards, bulletins, and engineering procedures; and, guidelines, standards and best practices applicable to the industry as a whole. In this section, FG&E discusses its own internal system planning guidelines, economic analyses, project prioritization methods, and distribution voltage and load-management practices.

1. ELECTRIC SYSTEM PLANNING GUIDELINES

FG&E employs the Unitil Service Corp. *Electric System Planning Guide* (see Attachment 3) to assess the adequacy of FG&E's transmission and sub-transmission systems. The *Unitil Electric System Planning Guide* provides detailed and systematic guidance on the assessment and evaluation of the sufficiency of 115 kV, 69 kV and 13.8 kV transmission, subtransmission and substation systems. Additionally, the *Unitil Electric System Planning Guide* directs FG&E as to the implementation, depth and frequency of transmission and sub-transmission planning studies.

FG&E has taken the opportunity to perform a general review and update of the *Unitil Electric System Planning Guide* which was originally issued in April 2000. This general review was used to revise the terminology employed and methodology used in generation dispatch and load forecasting sections of the *Planning Guide*. The most recent system planning studies reflect the use of these more conservative changes.

The generation dispatch methodology has changed from the *Unitil Electric System Planning Guide*, dated April 2000 and the December 2003 update. In general, the *Unitil Electric System Planning Guide*, dated April 2000, set generation on a unit-by-unit basis at 50% of historical output for all basecase and contingency conditions. As stated in the updated *Unitil Electric System Planning Guide*, dated December 2003, under a more reasonable approach, no more than one-half of the existing facilities should considered in commission and operation for the study period. This may be modeled conservatively by taking the most significant facilities out of service until the sum total of internal non-utility generation has been reduced by at least one-half for the typical historical output. This approach is used with all internal, non-utility generation, presently not under the direct control of FG&E. This change is a more reasonable and conservative approach to modeling generation under basecase and contingency conditions.

This filing also clarifies the load forecasting methodology used for the ten-year peak demand forecast. The updated version of the *Unitil Electric System Planning Guide*, dated December 2003, has incorporated the same load forecasting methodology as detailed in FG&E's January 2003 Annual Report in this docket.

The FG&E 01-67 2002 filing in January 2003 was completed with a voltage range of 90% to 110% of the system nominal voltage for all 115, 69, and 13.8kV non-distribution points. These limits have been changed to an upper limit of 105% of nominal system voltage, a more conservative range for determining system improvement requirements. No projects identified in the *FG&E Electric System Planning Study*, dated August 12, 2003, have resulted from this proposed change in voltage criteria. The updated *Unitil Electric System Planning Guide*, dated December 2003, recommends the same voltage criteria as 95% to 105%.

Additional system planning references that are relied upon in assessing and planning for system change and growth include FG&E construction standards, bulletins, and engineering procedures, and include all applicable industry guidelines, standards and best practices.

2. ELECTRIC DISTRIBUTION PLANNING

On a regular basis, FG&E evaluates all distribution systems at the circuit and substation level to identify deficiencies and to plan improvements. FG&E's evaluation process includes: 1) an analysis of individual circuit details on a cyclical basis using industry-standard circuit modeling and analysis software; and 2) periodic system-wide distribution planning studies that assess the adequacy of the existing and future FG&E electric distribution systems.

As part of its evaluative process, FG&E examines voltage levels, equipment loading, overall load balance, sufficiency of fault protection, and historical levels of reliability performance. These evaluations investigate and consider performance under present peak load and light load conditions, and projected future loads. As a result of the evaluation, recommendations for additions and/or modifications to system design are identified as part of a five-year planning horizon. FG&E employs a five-year plan to ensure sufficient lead-time to identify, plan, budget, design and construct the needed distribution system upgrades.

In general, FG&E conducts analyses of distribution circuits to consider normal, non-contingency operating conditions. Distribution circuit contingencies usually involve circuit faults that may result in brief outages of limited extent and duration until repairs are made.

At the substation level, certain major equipment key to system reliability, such as substation transformers, circuit breakers, and regulators, are not always easily repaired or restored. FG&E does plan for contingent loss of such equipment. On a regular basis, FG&E determines whether it has in inventory adequate emergency spare equipment, or whether the location may support alternate system configurations in order to meet operating guidelines, possibly for extended periods of time.

a. Distribution Voltage Guidelines

FG&E follows the principle that its electric distribution system should be designed and constructed so that the low voltage services (600 V and below) that are supplied to most customers primarily operate within the following range under steady-state conditions, as measured at the point of delivery:

Nominal Voltage	120/240 V	208Y/120 V	480Y/277 V
Upper limit (104.2%)	125 / 250 V	217 / 125 V	500 / 288 V
(A) Lower limit (95%)	114 / 228 V	197 / 114 V	456 / 263 V

(A) - corresponds to the latest ANSI C84.1 Range A Service Voltage

Practical design considerations or unusual operating circumstances may occasionally result in service voltages below the lower (A) limit. When such conditions arise, the following extended lower limit may be tolerated:

Nominal Voltage	120/240 V	208Y/120 V	480Y/277 V
(B) Lower limit (91.7%)	110 / 220 V	191 / 110 V	440 / 254 V

(B) - corresponds to the latest ANSI C84.1 Range B Service Voltage

Steady-state service voltages operating below the lower (B) limit are unacceptable under normal conditions. Normal conditions include common system activity, such as ordinary variations in loads and supply, voltage regulator or load-tap changer actions, routine system maintenance configurations, and emergency configurations after equipment failures or system faults have been removed.

Occasionally, abnormal conditions beyond FG&E's immediate control (including area voltage reduction actions, and at times where the system experiences active system faults) result in infrequent and time-limited periods when steady-state voltages above the upper limit or below the lower (B) limit may occur. However, when voltages occur outside these limits, FG&E takes prompt corrective action and engages in mitigation to ensure such irregularities are limited in extent, frequency, and duration.

b. Distribution Loading Guidelines

FG&E manages its distribution system by ensuring that the equipment used in the field, including transformers, wire and cable, regulators, breakers, reclosers, and switches adhere to a uniform set of rating standards and are deployed in a uniform manner. The rating and loading practices for distribution equipment generally follow established practices found in either the *Unitil Electrical Equipment Rating Procedures* or the *Unitil Electric System Planning Guide* for transmission equipment. See Attachment 3 and Attachment 4, respectively. FG&E anticipates that the Department may be particularly concerned with circuit load limits and transformer ratings, because damage and loss of this equipment may result in extensive and long term outages.

Substation Power Transformers are included under the Unitil Electrical Equipment Rating Procedures as transmission/subtransmission equipment. Specific ratings are established for individual units using particular load cycle profiles. See Appendix B.

Distribution Stepdown Transformers are rated using a common load cycle profile to establish a general set of ratings applicable to all.

Equipment with nameplate ratings, including regulators, breakers, reclosers, and switches are rated as provided by the manufacturer based on standard industry rating practices.

i. Circuit Load Limits

Distribution circuits are comprised of individual equipment components and associated protection and control systems. Circuit loading limits are restricted by: (1) the most limiting rating of the associated primary equipment; and (2) the operational limits of the associated protection and control systems.

Therefore, in order to ensure the highest level of reliability, FG&E rates entire circuits at the most limiting capacity of either.

c. Economic Analysis

The Unitil Service Corp. Economic Evaluation Procedures (included as Appendix C) provides a standard methodology used by FG&E to perform economic or cost-benefit evaluations of competing potential investments. The methodology set forth in Appendix C establishes a set of minimum evaluation requirements, and does not substitute for the business judgment of FG&E's management. Individual projects, therefore, may require additional and more specific economic evaluation than that described in Appendix C. The results of any analysis generated by the Economic Evaluation Procedures are also used in the budgeting process to compare potential projects.

C. OPERATING STUDY REPORT

FG&E is submitting two operating study reports with this filing. The *FG&E Electric System Planning Study* is an operational study of the 115kV and 69kV electric system. This report can be referenced in Attachment 1. The *FG&E Distribution System Planning Evaluation* is an operational study of the 13.8kV and 4kV electric distribution system. This report can be referenced in Attachment 2.

D. LISTING OF CRITICAL LOADS

FG&E has attached a listing of all critical loads sorted by town and the circuit by which they are fed in Attachment 6.

E. SIGNIFICANT RELIABILITY IMPROVEMENTS

As a result of the analysis and FG&E's long-term planning and budgeting process, a number of reliability improvements and infrastructure improvement projects are planned for 2004-2008. Because of FG&E's size, all these projects are significant from a reliability standpoint, so many are listed in spite of their relatively small budget impact. A list of the significant reliability improvement and infrastructure improvement projects can be referenced in Attachment 7.

F. PROJECT PRIORITIZATION GUIDELINES

FG&E employs uniform procedures for prioritizing capital projects. FG&E's project prioritization guidelines are given in Attachment 8.

ATTACHMENT 1

FG&E ELECTRIC SYSTEM PLANNING STUDY

Unitil
Unitil Service Corp.

Fitchburg Gas and Electric Light Company

Electric System Planning Study 2004-2013

Prepared By:

Paul Krell
Unitil Service Corp.
August 12, 2003

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

This study is an evaluation of the Fitchburg Gas and Electric Light Company (FG&E) electric power system. Its purpose is to identify when system growth is likely to cause main elements of the 115 kV, 69 kV and 13.8 kV subtransmission and substation systems to reach unacceptable design limits, and to provide recommendations for the most cost-effective system improvements. The study examines the FG&E system under summer peak load conditions in its normal operating configuration and in response to design contingencies for the loss of key system elements. The study covers the ten year period from 2004 through 2013.

The following FG&E system improvements are recommended from the results of this study:

Year	Project Description	Justification	Cost Estimate
2004	Reconductor 08 Line – Summer Street to Pleasant Street	overload, 115% LTE	$130,000
2004	Reconductor 09 Line – Summer Street to Pleasant Street	overload, 115% LTE	$130,000
2004	Install capacitors – 1.2 MVAr at Townsend S/S	p.f. correction	$50,000
2004	Install capacitors – 2.4 MVAr at West Townsend S/S	p.f. correction	$50,000
2005	Bus Expansion and new 115 kV line terminal at Flagg Pond *	transmission support	$780,000
2006	Install 69 kV Voltage Regulation at Flagg Pond **	voltage	$ TBD
2006	Install capacitors – approx. 1.2 MVAr system wide	p.f. correction	$20,000
2009	Install capacitors – approx. 1.2 MVAr system wide	p.f. correction	$20,000
2011	Install capacitors – approx. 1.2 MVAr system wide	p.f. correction	$20,000

(Note: cost estimates do not include General Construction Overheads)

* - subject to resolution of transmission planning issues with National Grid
** - subject to resolution of transmission operating issues with ISO-NE/REMVEC

2 INTRODUCTION

The purpose of this study is to plan for recommended system improvements to meet system design and performance objectives. It evaluates the adequacy of the FG&E electric system with respect to its external system supply interconnection, and internal system infrastructure throughout the study period. Conditions are examined at increasing load levels (representing expansion of electric customer load) under normal operating conditions, contingency scenarios for loss of major system elements, and extreme load levels above forecast design loads (representing load expansion plus exceptional hot weather conditions).

Detailed system models were developed for each year of design and extreme peak load levels. Power flow simulations were performed for normal and contingency configuration. From these simulations, system deficiencies were identified. System improvement alternatives were developed and tested to assess the impact they had on these deficiencies, and various improvement plans were compiled from these. Cost estimates were developed for each improvement alternative, and a cost-benefit comparison was made for the proposed system improvement plan options. Final recommendations represent the proposed system improvement plan.

3 SYSTEM DESCRIPTION

FG&E's electric power system is presently supplied from the National Grid (NGrid) 115 kV transmission system. Service is taken from NGrid at FG&E's Flagg Pond substation, located in southwest Fitchburg. Flagg Pond substation consists of a 115 kV high-side ring bus, two 115 - 69 kV, 60/80/100 MVA autotransformers, and a 69 kV low-side ring bus. Pinetree Power, a non-utility generating facility, also connects into the system at the Flagg Pond 69 kV ring bus. Pinetree Power typically supplies between 6 and 18 MW to the system. Flagg Pond substation is presently the only FG&E system supply.

Seven 69 kV subtransmission lines transfer power from Flagg Pond substation to ten distribution substations. Transformation at these substations steps down from the 69 kV subtransmission to the 13.8 kV and 4.16 kV distribution systems. A few 13.8 kV distribution circuits also serve quasi-subtransmission functions as alternate feeds between substations, and as supplies to three other distribution substations with their own 13.8 kV and 4.16 kV distribution systems.

Four NGrid 115 kV transmission lines terminate at the Flagg Pond 115 kV ring bus. Two of these lines operate in parallel from Pratts Junction substation in Massachusetts. The other two lines operate in parallel to Bellows Falls substation in Vermont. Both pairs of lines are double-circuited on common towers. The lines to Bellows Falls are a weak supply. Consequently, the FG&E system relies heavily on the supply from Pratts Junction.

As part of the regional New England bulk power system, the Flagg Pond 115 kV bus and these NGrid transmission lines are New England Power Pool (NEPOOL) classified Pool Transmission Facilities (PTF). PTF facilities are operated by the Independent System Operator of New England (ISO-NE), which is responsible for maintaining the integrity of the bulk power system.

The FG&E system has historically peaked during the summer season. This past summer, the FG&E system reached its highest recorded peak load of 97.978 MW at 14:00 on August 14, 2002.

4 SYSTEM LOADS

The scheduling of system modifications is dependent on the projected timetable of system loads that trigger the need. For planning purposes, system design load forecasts are based on a linear regression trending of historical system peaks. To account for differences from year to year in the severity of summer heat and other varying factors, one standard error from the historical trending is added into these forecasts. Details of the methodology and results are given in Appendix D – Load History and Design Forecasts.

The load at the Mill 8 paper plant is handled separately from the rest of the FG&E system loads in determining historical trends and forecasts. During the August 14, 2002 summer peak, load at Mill 8 reached 8 MW. This load is modeled fixed at an anticipated 10 MW going forward in the study years.

The resulting FG&E system loads used for this study are provided in Table 1 below.

Table 1. FG&E System Loads Under Study

Projected Summer Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2004	106.9	114.4
2005	107.8	115.3
2006	108.7	116.2
2007	109.6	117.2
2008	110.5	118.1
2009	111.4	119.0
2010	112.3	119.9
2011	113.2	120.8
2012	114.1	121.7
2013	115.0	122.6

5 SYSTEM MODELING AND ANALYSIS

Traditional load flow analysis methods were used to evaluate the FG&E system for this study. System modeling and power flow simulations were performed using TRANSMISSION 2000® Power Flow (version 4.20 Standard) software by Commonwealth Associates, Inc.[1] Because summer hot weather conditions present the greatest thermal constraints on system equipment, and FG&E is a historically summer peaking system, this study examines summer peak load conditions only.

An initial load flow model of the FG&E system was created to replicate conditions during the 2002 summer peak. Details of the FG&E system infrastructure were assembled using best available data on system impedances, transformer ratios, equipment ratings, etc. This model was added to a representation of the surrounding external power system from load flow cases provided by ISO-NE. Bus loads were compiled for the model by aggregating substation, circuit, and large customer load information for the August 14, 2002 summer peak. Much of this load information is available only as non-coincident, monthly peak demands. With the operating configuration, substation capacitors, and internal generation (i.e. Pinetree Power) set in the model to actual conditions at the time, overall scaling adjustments were made to bus loads to reasonably match the power flow simulation results to actual recorded system flows for the peak day and hour. Once completed, this established a confident model representing the FG&E system as it existed during the 2002 summer peak.

Base case models for study of future years were developed from this 2002 peak model. Anticipated system configuration and known individual load adjustments were made. Then

1 Commonwealth Associates, Inc., P.O. Box 1124, Jackson, Michigan 49204-1124 (Tel. 517 788-3000)

overall bus loads were grown to set the total FG&E system load plus internal losses, as seen at the system supply delivery points, to the study loads (Section 4 – System Loads). Internal, non-utility generation was left set to their output levels at the time of the 2002 summer peak.

These base cases were used to analyze normal operating conditions, extreme peak conditions, and all major design contingencies for each of the ten years under study. Unacceptable system conditions were identified based on the Unitil Electric System Planning Guide. Details summarizing these criteria are given in Appendix A – Evaluation Criteria.

6 SYSTEM POWER FACTOR

Load power factor for the FG&E system is subject to the guidelines of ISO-NE Operating Procedure No. 17 - Load Power Factor Correction (OP-17), and service agreement requirements with National Grid. In both cases, system power factor capabilities for the purposes of this study are designed to comply with the load power factor curves issued by the NEPOOL Voltage Task Force (VTF) in October 29, 2002. The break points for these curves are summarized in the following table for the ISO-NE Harriman-Central Area.

Table 6.1 ISO-NE Harriman-Central Area – Load Power Factor Standards

Equivalent Load (% of Peak)	Minimum p.f.	Maximum p.f.
40%	0.750, lagging	1.000, unity
75%	0.950, lagging	1.000, unity
100%	0.990, lagging	0.995, leading

During the summer peak on August 14, 2002 at 14:00, the FG&E system was operating at a net power factor of 0.969 (lagging), as seen at the NGrid 115 kV and Pinetree Power 69 kV system supply delivery points. For unrelated reasons, several system capacitors were not switched in at the time.

The availability of Pinetree Power generation influences FG&E system power factor by reducing reactive losses through the Flagg Pond autotransformers. FG&E responsibilities for system power factor assume the need for reactive compensation capabilities to meet ISO-NE load power factor guidelines with or without Pinetree Power generation.

In 2004 at a system peak design load of 106.9 MW, the estimated net power factor is expected to be approximately 0.986 (lagging) as seen at the system supply delivery points. By 2013 at a system peak design load of 115.0 MW, with no improvements made, this estimated net power factor is expected to be approximately 0.980 (lagging). These are with all existing substation capacitors switched into service, and with Pinetree Power generation out of service.

At these loads levels, approximately 7.0 MVAr of cumulative p.f. correction capacitor additions are needed to achieve a minimum of 0.990 p.f. (lagging) over the ten year study period. The following table provides a schedule of estimated requirements.

Table 6.2 FG&E System – Anticipated Power Factor Correction Requirements

Year	Uncorrected System Load * (MW)	(MVAr)	p.f.	Est. Minimum p.f. correction (MVAr)
2004	106.9	18.1	0.986, lagging	2.9
2005	107.8	19.0	0.985, lagging	3.6
2006	108.7	19.5	0.984, lagging	4.0
2007	109.6	19.9	0.984, lagging	4.3
2008	110.5	20.5	0.983, lagging	4.8
2009	111.4	21.0	0.983, lagging	5.1
2010	112.3	21.8	0.982, lagging	5.8
2011	113.2	22.4	0.981, lagging	6.3
2012	114.1	22.9	0.980, lagging	6.7
2013	115.0	23.4	0.980, lagging	7.0

* - with no improvements, all existing substation capacitors switched into service, and Pinetree Power generation out of service

The following recommendations are given to meet a minimum power factor capability of 0.990 (lagging) at system peak design load levels:

2004 - install 3.6 MVAr of p.f. correction capacitors
2006 - install 1.2 MVAr additional p.f. correction capacitors (4.8 MVAr cumulative)
2009 - install 1.2 MVAr additional p.f. correction capacitors (6.0 MVAr cumulative)
2011 - install 1.2 MVAr additional p.f. correction capacitors (7.2 MVAr cumulative)

The Townsend/W.Townsend areas would benefit the most from voltage support provided by capacitor additions. Townsend S/S presently has two (2) 1200 kVAr distribution banks installed immediately beyond the fence on circuits 15W15 and 15W16 (one each). While Townsend would benefit the most, it is recommended that only 1200 kVAr worth of additional capacitors be added here. The remaining 2400 kVAr should be added as a switched bank off of the 13.8 kV bus at West Townsend S/S. Remote control through the SCADA system is recommended at both locations, in order to dispatch units based on real-time VAr requirements.

Capacitor additions in later years can be targeted to areas as future conditions dictate.

7 SYSTEM CONSTRAINTS

The following summarizes the system deficiencies driving improvement proposals during the ten year study period, with the load level and projected year in which they first occur.

Year	Load Level (MW)	System Condition	Circumstances
2004	106.9	conductor overload – 08 Line (Summer St. to Pleasant St.)	Loss of 09 Line
		conductor overload – 09 Line (Summer St. to Pleasant St.)	Loss of 08 Line
	114.4	low voltage – Townsend area	Extreme Peak (all in)

The following sections describe each of these constraints in detail. Additional concerns for the concurrent loss of both of National Grid's I-135S and J-136S lines between Pratts Junction substation and Flagg Pond substation are described here as well.

7.1 08 Line, Summer Street to Pleasant Street – Phase Conductors

1/0 ACSR phase conductors
247 A summer Normal limit
294 A summer LTE limit

Summary:
Conductor ratings exceeded at peak loading under the following design conditions:

2004 - Loss of 09 Line

Details:
Normal System Configuration – no system element outages

- From 2004 through 2013 and beyond, loading on the 08 Line phase conductors in the normal system configuration with no system element outages is expected to remain below the 247 A Summer Normal Limit of the 1/0 ACSR phase conductors for system design loads well above 115.0 MW.

Extreme Peak System Load – no system element outages

- From 2004 through 2013 and beyond with no system element outages, loading on the 08 Line phase conductors in the normal system configuration is expected to remain below the 294 A Summer LTE Limit for loads up to and above the 2013 extreme peak design load of 122.6 MW. Exposure to emergency operation above the 247 A Normal Limit is estimated to be as much as 13 total hours in 2013, but no more than 6 consecutive hours on the peak day.

Loss of 09 Line, Summer Street to West Townsend (Pinetree generation off line)

- For loss of a non-radial line, after switching, planning guidelines do not allow load to remain out of service, but operation up to LTE Limits is allowed for up to 12 hours.
- In 2004 and beyond, after switching to restore all load for loss of the 09 Line, loading on the 08 Line phase conductors between Summer Street S/S and Pleasant Street S/S is expected to exceed the 294 A Summer LTE Limit of the 1/0 ACSR

phase conductors for total system loads of approximately 96 MW or greater. Exposure to these load levels is estimated to be on the order of 100± hours (on 12 to 15 individual days, up to 5 days consecutively) in 2004, with as many as 13 consecutive hours on the peak day. At the 106.9 MW system design load for 2004, the 08 Line phase conductors are forecast to reach 338 A (137% of Normal Limit, 115% of LTE Limit).

Recommendations:

- In 2004, implement system improvement (see section 8 – System Improvement Options) to relieve unacceptable 08 Line phase conductor loadings.

7.2 <u>09 Line, Summer Street to Pleasant Street – Phase Conductors</u>

1/0 ACSR phase conductors
247 A summer Normal limit
294 A summer LTE limit

Summary:

Conductor ratings exceeded at peak loading under the following design conditions:

2004 - Loss of 08 Line

Details:

Normal System Configuration – no system element outages

- From 2004 through 2013 and beyond, loading on the 09 Line phase conductors in the normal system configuration with no system element outages is expected to remain below the 247 A Summer Normal Limit of the 1/0 ACSR phase conductors for system design loads well above 115.0 MW.

Extreme Peak System Load – no system element outages

- From 2004 through 2013 and beyond with no system element outages, loading on the 09 Line phase conductors in the normal system configuration is expected to remain below the 247 A Normal Limit, as well as the 294 A Summer LTE Limit, for loads up to and above the 2013 extreme peak design load of 122.6 MW.

Loss of 08 Line, Summer Street to Townsend (Pinetree generation off line)

- For loss of a non-radial line, after switching, planning guidelines do not allow load to remain out of service, but operation up to LTE Limits is allowed for up to 12 hours.
- In 2004 and beyond, after switching to restore all load for loss of the 08 Line, loading on the 09 Line phase conductors between Summer Street S/S and Pleasant Street S/S is expected to exceed the 294 A Summer LTE Limit of the 1/0 ACSR phase conductors for total system loads of approximately 96 MW or greater. Exposure to these load levels is estimated to be on the order of 100± hours (on 12 to 15 individual days, up to 5 days consecutively) in 2004, with as many as 13 consecutive hours on the peak day. At the 106.9 MW system design load for

2004, the 08 Line phase conductors are forecast to reach 339 A (137% of Normal Limit, 115% of LTE Limit).

Recommendations:

- In 2004, implement system improvement (see section 8 – System Improvement Options) to relieve unacceptable 09 Line phase conductor loadings.

7.3 Townsend Area – System Voltages

Summary:

Poor system voltages at peak loading under the following design conditions:

2004 - Extreme Peak loading, no system element outages, Pinetree generation off line
2005 - Loss of 08 Line, Pinetree generation off line
2007 - Loss of 09 Line, Pinetree generation off line
2008 - Loss of 01 Line, Pinetree generation off line
2009 - Loss of 02 Line, Pinetree generation off line
2010 - Base system loading, no system element outages, Pinetree generation off line
2013 - Loss of Flagg Pond No.1 Autotransformer, Pinetree generation off line
Loss of Flagg Pond No.2 Autotransformer, Pinetree generation off line
2010 to 2013 – Loss of I-135S, J-136S, I-135N, or J-136N Lines

Details:

This constraint arises from the lack of voltage regulation throughout the FG&E subtransmission system from the Flagg Pond 115 kV all the way to Townsend S/S and West Townsend S/S. At peak loads, there is roughly 0.7% to 0.9% voltage drop through the Flagg Pond autotransformers (depending on status of Pinetree Power generation), 0.8% voltage drop on the 69 kV from Flagg Pond to Summer Street, and 3.4% voltage drop along the 08 Line from Summer Street to Townsend S/S. With the 115 kV supply into Flagg Pond operating at roughly 97% to 98% in the model for a 2004 system design load of 106.9 MW (again depending on Pinetree Power generation), 69 kV voltages on the 08 Line at Townsend S/S start off at 92% to 93% or nominal (within 2% or 3% of minimum guidelines). This quickly deteriorates with a few years of load growth, or the contingent loss of the 08 Line or 09 Line.

Normal System Configuration – no system element outages (Pinetree generation off line)

- From 2004 through 2009, 69 kV transmission voltages on the 08 and 09 Lines in the normal system configuration with no system element outages are expected to remain above 90% for system design loads up to roughly 112 MW. Similarly, voltages on the 13.8 kV regulated buses at Townsend S/S and West Townsend S/S are expected to remain above 97.5% (117 V on 120 V base).
- In 2010, 69 kV transmission voltages on the 08 Line are expected to drop below 90%, and voltage on the 13.8 kV regulated bus at Townsend S/S is expected to drop below 97.5% in the normal system configuration with no system element outages.

Extreme Peak System Load – no system element outages (Pinetree generation off line)

- In 2004 and beyond, 69 kV transmission voltages on the 08 Line are expected to drop below 90%, and voltage on the 13.8 kV regulated bus at Townsend S/S is expected to drop below 97.5% in the normal system configuration with no system element outages for extreme peak loads of approximately 112 MW or greater. Exposure to these load levels is estimated to be on the order of 5 to 13 hours (up to 6 hours consecutively) in 2004 on the one to three extreme peak days. This exposure increases in 2005 to 9 to 19 hours (up to 7 hours consecutively) on two to four extreme peak days.
- Voltages on the 09 Line and at Lunenburg S/S are also expected to fall below tolerable levels at extreme peak loads in subsequent years.

Loss of 08 Line, Summer Street to Townsend (Pinetree generation off line)

- For loss of a non-radial line, after switching, planning guidelines do not allow load to remain out of service, but operation up to LTE Limits is allowed for up to 12 hours.
- In 2004, after switching to restore all load for loss of the 08 Line, system voltages remain above tolerable levels.
- In 2005, after switching to restore all load, 69 kV transmission voltages on the 08 Line are expected to drop below 90% at the 107.8 MW system design load.
- In 2006, after switching to restore all load, voltage on the 13.8 kV regulated bus at Townsend S/S is expected to drop below 97.5% at the 108.7 MW system design load.

Loss of 09 Line, Summer Street to Townsend (Pinetree generation off line)

- For loss of a non-radial line, after switching, planning guidelines do not allow load to remain out of service, but operation up to LTE Limits is allowed for up to 12 hours.
- In 2004 through 2006, after switching to restore all load for loss of the 09 Line, system voltages remain above tolerable levels.
- In 2007, after switching to restore all load, 69 kV transmission voltages on the 09 Line are expected to drop below 90% at the 109.6 MW system design load.
- In 2008, after switching to restore all load, voltage on the 13.8 kV regulated bus at Townsend S/S is expected to drop below 97.5% at the 110.5 MW system design load.

Loss of 01 Line, Flagg Pond to Summer Street (Pinetree generation off line)

- For loss of a non-radial line, after switching, planning guidelines do not allow load to remain out of service, but operation up to LTE Limits is allowed for up to 12 hours.
- In 2004 through 2007, after switching to restore all load for loss of the 01 Line, system voltages remain above tolerable levels.
- In 2008, after switching to restore all load, 69 kV transmission voltages on the 08 Line are expected to drop below 90%, and voltage on the 13.8 kV regulated bus at Townsend S/S is expected to drop below 97.5%, at the 110.5 MW system design load.

Loss of 02 Line, Flagg Pond to Summer Street (Pinetree generation off line)

- For loss of a non-radial line, after switching, planning guidelines do not allow load to remain out of service, but operation up to LTE Limits is allowed for up to 12 hours.
- In 2004 through 2008, after switching to restore all load for loss of the 02 Line, system voltages remain above tolerable levels.
- In 2009, after switching to restore all load, 69 kV transmission voltages on the 08 Line are expected to drop below 90%, and voltage on the 13.8 kV regulated bus at Townsend S/S is expected to drop below 97.5%, at the 111.4 MW system design load.

Additional Contingencies

- Other contingencies, such as loss of either Flagg Pond autotransformer or various losses of the 115 kV lines into Flagg Pond, also result in unacceptable voltages in the areas supplied by the 08 and 09 Lines in later years.

Recommendations:

- In 2004 and 2005, accept risk of low distribution voltages out of Townsend S/S under extreme peak conditions, due to limited exposure.
- In 2005, accept risk of low 69 kV transmission voltages at Townsend S/S for loss of the 08 Line, due to minimal exposure and limited consequence.
- In 2006, implement system improvement (see section 8 – System Improvement Options) to relieve unacceptable low voltages in various areas supplied by 08 and 09 Lines.

7.4 I-135S and J-136S Lines (NGrid) – Double-Circuit Transmission Structures

In addition to the design contingencies described above, concerns continue for the concurrent loss of both of National Grid's I-135S and J-136S lines between Pratts Junction substation and Flagg Pond substation. The reason for reviewing this contingency is these 115 kV transmission lines are built double-circuited on common structures. It can be contended that a single contingency scenario can take both lines out of service at the same time. Lightning strikes at a common structure are one example, which is believed to have happened on occasion in the past.

Power flow simulations run for this study are unable to converge to a solution for the concurrent loss of the I-135S and J-136S. This suggests the possibility of voltage collapse at these load levels. Such an event would affect the remaining areas on the I-135N and J-136N lines from Flagg Pond to NGrid's Bellows Falls substation including the entire FG&E system, NGrid's Ashburnham and East Winchendon substations, and the PSNH system in the area of their Monadnock substation.

This issue has been identified in the past, and equipment has been installed by both FG&E and NGrid to automatically shed load using undervoltage relaying as a remedy. However, it is unclear from this study whether area loads (beyond just FG&E) will have grown beyond the point that the installed load shedding will not be adequate to avoid widespread problems. Further study is expected from NGrid to better quantify the conditions.

Recommendations:

- At this time, National Grid has indicated that it is looking at two options for addressing these concerns (see section 8 – System Improvement Options). Unitil will continue to remain engaged in active discussions with National Grid to quantify conditions and plan corrective measures that may be needed.

8 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement alternatives examined to address the deficiencies identified earlier in this report.

8.1 08 Line and 09 Line Conductor Overload Options

The following two alternatives were examined to avoid conductor overloads identified on the 08 Line and 09 Lines between Summer Street S/S and Pleasant Street S/S (see section 7.1 – 08 Line, Summer Street to Pleasant Street – Phase Conductors, and section 7.2 – 09 Line, Summer Street to Pleasant Street – Phase Conductors)

8.1.1 Reconductor 08 and 09 Lines – Summer Street to Pleasant Street

Summary:

Replace the 1/0 ACSR phase conductors with 556 ACSR on both the 08 Line and the 09 Line in their entirety from Summer Street S/S to Pleasant Street S/S. Similarly, replace any in-line switches, connectors, hardware and other associated equipment with ratings of less than 400 amps.

The choice of 556 ACSR conductors is in keeping with the possible future use of these lines to transmit power from a new system supply in Townsend/W.Townsend area south to Summer Street S/S.

Cost Estimate:

Reconductor 08 Line – Summer Street to Pleasant Street	$130,000
Reconductor 09 Line – Summer Street to Pleasant Street	$130,000
Total (w/o General Construction OHs)	$260,000

Results:

Normal System Configuration

- From 2004 through 2013 and beyond, loading on the 08 Line and 09 Line phase conductors in the normal system configuration with no system element outages is expected to remain well below the 749 A Summer Normal Limit of 556 ACSR phase conductors for peak design and extreme peak loads approaching far beyond the limits of this study.

Loss of 09 Line, Summer Street to West Townsend

- From 2004 through 2013 and beyond, after switching to restore all load for loss of the 09 Line, loading on the 08 Line with 556 ACSR phase conductors between Summer Street S/S and Pleasant Street S/S is expected to remain well below the 749 A Summer Normal Limit (52% of Normal Limit at peak design load in 2013).

Loss of 08 Line, Summer Street to Townsend

- From 2004 through 2013 and beyond, after switching to restore all load for loss of the 08 Line, loading on the 09 Line with 556 ACSR phase conductors between Summer Street S/S and Pleasant Street S/S is expected to remain well below the 749 A Summer Normal Limit (52% of Normal Limit at peak design load in 2013).

8.1.2 Construct New 69 kV Line – Summer Street to Pleasant Street

Summary:

Construct a new 69 kV Line from Summer Street S/S to Pleasant Street S/S. Construction to include 556 ACSR phase conductors on separate structures from the 08 or 09 Lines, the addition of a new 69 kV line terminal at Summer Street S/S, and tie switch additions at Pleasant Street S/S. The proposed new configuration would have the new line carrying the entire Pleasant Street S/S load, the 08 Line carrying Townsend S/S, and the 09 Line carrying Lunenburg S/S and West Townsend S/S.

Cost Estimate:

Relocate 06 Line Position to Bus #1 – Summer Street S/S	$240,000
New 69 kV Line Addition at Bus #2 – Summer Street S/S	$110,000
Construct New 69 kV Line – Summer Street to Pleasant Street	$280,000
Switch Addition(s) – Pleasant Street	$25,000
Total (w/o General Construction OHs)	$655,000

Results:

New System Configuration

- From 2004 through 2013 and beyond, loading on the 08 Line and 09 Line in the new system configuration with no system element outages is expected to remain well below the 247 A Summer Normal Limit of the 1/0 ACSR phase conductors for peak design and extreme peak loads beyond the limits of this study.
- From 2004 through 2013 and beyond, loading on the new line in the new system configuration with no system element outages is expected to remain well below the 749 A Summer Normal Limit of the 556 ACSR phase conductors for peak design and extreme peak loads beyond the limits of this study.

Loss of 09 Line, Summer Street to West Townsend

- From 2004 through 2013 and beyond, after switching to restore all load for loss of the 09 Line, loading on the remaining 08 Line and new line is expected to remain well below the Summer Normal Limits on their respective conductors.

Loss of 08 Line, Summer Street to Townsend

- From 2004 through 2013 and beyond, after switching to restore all load for loss of the 08 Line, loading on the remaining 09 Line and new line is expected to remain well below the Summer Normal Limits on their respective conductors.

8.1.3 Advantages / Disadvantages

Following implementation of either of the above options, the next loading problem (overload of the line sections from Pleasant Street to Lunenburg for outage of one of the lines) exists at a system load beyond the ten year study period. There is no benefit of either option in deferring this constraint.

Construction of a new line from Summer Street to Pleasant Street does offer some reliability benefit, by allocating the Pleasant Street, Lunenburg, Townsend and West Townsend loads among three lines instead of two. However, with greater conductor capacity on the 08 and 09 lines, switching remains available between just the two lines after an initial outage. Any reliability advantage of avoiding customer outages outright with a third line comes at significantly greater cost.

Both options are essentially equivalent as far as system losses. Similarly, voltages in the Townsend/W.Townsend area are largely the same with either option, whether under normal conditions or after switching for contingencies. This is due to the short conductor distance between Summer Street and Pleasant Street, relative to the longer distances continuing to Lunenburg and Townsend or West Townsend.

8.1.4 Recommendation

Reconductoring of the 08 and 09 lines is the recommended solution to the present conductor constraints. It is the least cost option, and provides comparable benefits.

- In 2004, reconductor the 08 Line and 09 Line with 556 ACSR between Summer Street S/S and Pleasant Street S/S.

8.2 Townsend Area Voltage Options

The following three alternatives were considered to improve inadequate voltage levels identified at Townsend S/S, and later at West Townsend S/S and Lunenburg S/S (see section 7.3 – Townsend Area – System Voltages)

8.2.1 Improve 115 kV Operating Voltages in the Flagg Pond Area

Summary:
Implement improved voltage control of the 115 kV bulk transmission system in the Flagg Pond area.

Cost Estimate: negligible (no direct capital investment by FG&E)

Results:
Depending on the amount of improvement that may be achieved, several years worth of postponement can be gained for the various voltage concerns itemized in section 7.3 – Townsend Area – System Voltages. In general, roughly 2 years of postponement is gained for each 1% increase of 115 kV voltage.

Challenges:
The operating voltage of the 115 kV transmission supply into Flagg Pond S/S is largely out of the direct control of FG&E. National Grid owns the four 115 kV transmission lines that terminate at Flagg Pond and much of surrounding system, especially to the south from Pratts Junction. Regional planning and operation of the transmission system are the responsibilities of NEPOOL and ISO-New England, with REMVEC being the satellite control center for the area. Any changes to generation dispatch or transmission voltage control to affect the 115 kV supply voltage into Flagg Pond will need to be established through these entities. The prospects for this option are not known at this time.

8.2.2 Change No-Load Taps on Flagg Pond 115 – 69 kV Autotransformers

Summary:
Reset the No-Load Taps on the 4T1 and 4T2 autotransformers at Flagg Pond from their present 115 kV position to the 112.5 kV position.

Cost Estimate: negligible (no capital investment)

Results:
A general increase of 2% to 3% in 69 kV system voltages across the board during peak loads. This will postpone the various voltage concerns itemized in section 7.3 – Townsend Area – System Voltages by roughly 4 to 6 years, but will not eliminate them over the long term.

Challenges:
A significant possible drawback to this approach is the risk of unacceptably high 69 kV system voltages during lighter load periods with higher voltages on the 115 kV transmission system. This requires a level of review, including close coordination with National Grid and ISO-NE, beyond the scope of this study.

8.2.3 Install 69 kV Regulation at Flagg Pond S/S

Summary:
Install standalone 69 kV regulating transformers at Flagg Pond substation, or replace/retrofit the two 115 - 69 kV autotransformers with Load-Tap Changing units.

Cost Estimate: $ TBD

Results:
Gaining +/- 10% voltage regulation at the Flagg Pond 69 kV bus should entirely resolve the concerns itemized in section 7.3 – Townsend Area – System Voltages for many years beyond the end of the study period.

Challenges:
Need to coordinate operation of regulating transformers for possible reverse power flow from internal generation (i.e. Pinetree Power) versus light system loads.

8.2.4 Construct New System Supply in Townsend/W.Townsend Area

Summary:
Create a new transmission substation for supply into the northern end of the FG&E system in the Townsend/W.Townsend area.

Cost Estimate: $ TBD

Results:
A new system supply into the FG&E system in the Townsend area is expected to entirely resolve the concerns itemized in section 7.3 – Townsend Area – System Voltages for many years beyond the end of the study period.

Challenges:
This option would require extensive additional research to determine its feasibility. The assumption is that the National Grid transmission easement from Milford, NH to Townsend, MA would provide some opportunity for 115 kV or 345 kV line construction.

8.2.5 Advantages / Disadvantages

Operational changes such as improving the 115 kV system voltage into Flagg Pond, or switching the no-load tap selections on the Flagg Pond autotransformers, appear to be the least cost options at this time. However, their feasibility is unknown. Their affect would be to postpone concerns for a few years before another improvement is needed. Sufficient time is presently available to determine the opportunity and benefits before implementation would be needed in 2006 as proposed.

Installing of 69 kV regulation at Flagg Pond S/S will require significant capital investment. It would provide much more operational flexibility, with benefits for the entire FG&E system many years into the future. It is believed that sufficient time is available to study this option, develop a design and construct in time for implementation in 2006 as proposed.

Creation of a new system supply in the Townsend/W.Townsend area is unquestionably the most expensive option examined here. For a significantly greater investment, it would provide a major expansion of capacity to take the system many years into the future. However, there would be many large challenges to study, design and construct in time for implementation by 2006 as proposed.

8.2.6 Recommendation

To overcome the concerns for system voltage in the Townsend area, several actions are recommended in the near term.

- Conduct a review of actual system voltage performance at the 115 kV supply into Flagg Pond S/S, on the 69 kV at Flagg Pond and Summer Street S/S, and on the 13.8 kV at Townsend S/S and West Townsend S/S in conjunction with LTC operation, in order to verify concerns.
- Work with National Grid, REMVEC and others to determine opportunities for improved 115 kV operating voltage in the area.
- Study further the feasibility of the system additions outlined here, with the objective of driving implementation by 2006.

In all likelihood, the addition of 69 kV regulation at Flagg Pond S/S is the most realistic long term solution to these particular concerns.

8.3 115 kV Transmission System Options

National Grid has indicated they are studying the following two alternatives to address the unacceptable conditions on the 115 kV transmission system in the Flagg Pond area for the coincident loss of the I-135S and J-136S Lines from Pratts Junction (see section 7.4 – I-135S and J-136S Lines – Double Circuit Transmission Structures).

8.3.1 Construct New 115 kV Line – Pratts Junction to Flagg Pond

Summary:

National Grid to construct a new 115 kV Line from Pratts Junction S/S to Flagg Pond S/S. FG&E to expand the Flagg Pond 115 kV bus and add new line terminal.

Cost Estimate:

Construct New 115 kV Line – Pratts Junction to Flagg Pond	(NGrid investment)
Bus Expansion and New 115 kV Line Addition – Flagg Pond S/S	$780,000
Total (w/o General Construction OHs)	$780,000

Results:

Loss of I-135S and J-136S Lines, Pratts Junction to Flagg Pond:

- From 2004 through 2013, the FG&E system operates within normal loading and voltage limits after the coincident loss of both the I-135S and J-136S lines, with or without Pinetree Power generation on line.

Challenges:

National Grid is still in their planning process at the time of this report. It is not expected that this option can be designed and constructed before 2005.

8.3.2 Construct New 345 - 115 kV Transmission Substation (NGrid) – Fitzwilliam, NH

Summary:
National Grid to construct a new transmission substation in Fitzwilliam, NH. Plan is to tap the 379 Line, step down with a new autotransformer to 115 kV, and feed into the either the I-135N or J-136N lines.

Cost Estimate: no direct capital investment by FG&E

Results:
Loss of I-135S and J-136S Lines, Pratts Junction to Flagg Pond:

- From 2004 through 2013, the FG&E system operates within normal loading and voltage limits after the coincident loss of both the I-135S and J-136S lines, with or without Pinetree Power generation on line.

8.3.3 Advantages / Disadvantages
System supply into FG&E appears to be adequate with implementation of either of the above options. Neither option is expected to be in service before 2005. Clearly, there is more direct cost to FG&E with the 115 kV line addition into Flagg Pond. However, this would be ISO-NE PTF investment, with some partial recovery expected. A decision on either option is largely dependent on National Grid and ISO-New England considerations.

8.3.4 Recommendation
Continue ongoing discussion with NGrid to finalize these decisions and press for implementation as soon as possible. Expectations are as follows:

- In 2004, continued risk of transmission failure for loss of a double-circuit tower.
- In 2005, complete construction and place into service system improvement for 115 kV transmission system in the Flagg Pond area.

9 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	Recommendation	Cost Estimate
2004	Reconductor 08 Line – Summer Street to Pleasant Street	$130,000
2004	Reconductor 09 Line – Summer Street to Pleasant Street	$130,000
2004	Install capacitors – 1.2 MVAr at Townsend S/S	$50,000
2004	Install capacitors – 2.4 MVAr at West Townsend S/S	$50,000
2004	Accept risk of low distribution voltages out of Townsend S/S under extreme peak conditions	
2004	Continue discussions w/ NGird on 115 kV transmission supply integrity, and decision on plans to either build new 115 kV line into Flagg Pond or new 345 - 115 kV substation in Fitzwilliam, NH	
2004	Conduct review of FG&E subtransmission voltage performance to Townsend S/S and West Townsend S/S	
2004	Work with National Grid, REMVEC and others on opportunities for improved 115 kV operating voltage	
2005	Bus Expansion and new 115 kV line terminal at Flagg Pond *	$780,000
2005	Accept risk of low distribution voltages out of Townsend S/S under extreme peak conditions	
2005	Accept risk of low 69 kV at Townsend S/S for the loss of the 08 Line	
2006	Install 69 kV Voltage Regulation at Flagg Pond **	$ TBD
2006	Install capacitors – approx. 1.2 MVAr system wide	$20,000
2009	Install capacitors – approx. 1.2 MVAr system wide	$20,000
2011	Install capacitors – approx. 1.2 MVAr system wide	$20,000

APPENDICES

A Evaluation Criteria

B FG&E Line Ratings

C FG&E Transformer Ratings

D System Load

E Base Case Studies

F Contingency Switching Studies

G References

H Diagrams

APPENDIX A

EVALUATION CRITERIA

The following summarizes the application of electric system planning guidelines as used in this study. These criteria are based on Unitil's Electric System Planning Guide (April, 2000)

1 LOADING

Peak design conditions – all elements in service:

- All load in service
- All elements operating within Normal Limit ratings w/ half of internal, non-utility generating units out of service

Peak design conditions – loss of non-radial lines (after switching):

- All load restored to service
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

Peak design conditions – loss of radial lines, or system supply transformers (after switching):

- Up to 30 MW of load left out of service for up to 24 hours
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

Extreme Peak conditions – all elements in service:

- All load in service
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

2 VOLTAGE

All conditions:

- For all 115, 69 and 13.8 kV non-distribution[1] points: 90% < V < 110%
- For all 13.8 and 4.16 kV distribution[2] points: 97.5% < V < 104.167%

Note: these criteria represent proposed updates to the Electric System Planning Guide (April, 2000)

1 "non-distribution" indicates only locations that are not direct supply outputs for distribution circuit loads
2 "distribution" indicates locations that are direct supply outputs for distribution circuit loads, after all transformation and/or voltage regulation

APPENDIX B

FG&E LINE RATINGS

The following is a listing of the present summer and winter thermal ratings for FG&E 69 kV and 13.8 kV Lines studied in this report.

			Summer Capacity				Winter Capacity			
Line Section	Limiting Factor	Nominal Voltage	Normal Limit (Amps)	LTE Limit (Amps)	Normal Limit (MVA)	LTE Limit (MVA)	Normal Limit (Amps)	LTE Limit (Amps)	Normal Limit (MVA)	LTE Limit (MVA)
01 Flagg Pond – Summer Street	556 ACSR Parakeet	69 kV	749	915	89.5	109.4	982	1102	117.4	131.7
01 River Street Tap	556 ACSR Parakeet	69 kV	749	915	89.5	109.4	982	1102	117.4	131.7
01 Princeton Road Tap	556 ACSR Parakeet	69 kV	749	915	89.5	109.4	982	1102	117.4	131.7
02 Beech Street Tap	2/0 Cu 7 str.	69 kV	373	451	44.6	53.9	486	543	58.1	64.9
02 Flagg Pond – Summer Street	556 ACSR Parakeet	69 kV	749	915	89.5	109.4	982	1102	117.4	131.7
02 Beech Street Tap	2/0 Cu 7 str.	69 kV	373	451	44.6	53.9	486	543	58.1	64.9
03 Flagg Pond – River Street	556 ACSR Parakeet	69 kV	749	915	89.5	109.4	982	1102	117.4	131.7
03 Princeton Road Tap	556 ACSR Parakeet	69 kV	749	915	89.5	109.4	982	1102	117.4	131.7
06 Summer Street–Sawyer Passway	336 AA Tulip	69 kV	531	645	63.5	77.1	694	777	82.9	92.9
08 Summer Street – Townsend	1/0 ACSR Raven	69 kV	247	294	29.5	35.1	322	354	38.5	42.3
08 Lunenburg Tap	1/0 ACSR Raven	69 kV	247	294	29.5	35.1	322	354	38.5	42.3
09 Summer Street – W.Townsend	1/0 ACSR Raven	69 kV	247	294	29.5	35.1	322	354	38.5	42.3
09 Lunenburg Tap	1/0 ACSR Raven	69 kV	247	294	29.5	35.1	322	354	38.5	42.3
010 Townsend – W.Townsend	1/0 ACSR Raven	69 kV	247	294	29.5	35.1	322	354	38.5	42.3

Line Section	Limiting Factor	Nominal Voltage	Summer Capacity Normal Limit (Amps)	Summer Capacity LTE Limit (Amps)	Summer Capacity Normal Limit (MVA)	Summer Capacity LTE Limit (MVA)	Winter Capacity Normal Limit (Amps)	Winter Capacity LTE Limit (Amps)	Winter Capacity Normal Limit (MVA)	Winter Capacity LTE Limit (MVA)
1303 Summer Street – Sawyer Passway	336 AA Spacer	13.8 kV	531	645	12.7	15.4	694	777	16.6	18.6
1309 Summer Street – Sawyer Passway	477 AA	13.8 kV	663	808	15.8	19.3	868	974	20.7	23.3
1W1 Beech Street – Wallace Road	CTs	13.8 kV	400		9.6		400		9.6	
1W1 Nockege – Wallace Road	Phase Trip	13.8 kV	420	420	10.0	10.0	420	420	10.0	10.0
22W1 Sawyer Passway – Wallace Road	350 Cu UG	13.8 kV	435		10.4		435		10.4	
22W10Sawyer Passway – Nockege	350 Cu UG	13.8 kV	435		10.4		435		10.4	
22W17Sawyer Passway – Nockege	350 Cu UG	13.8 kV	435		10.4		435		10.4	

APPENDIX C

FG&E TRANSFORMER RATINGS

The following is a listing of the present summer and winter thermal ratings for FG&E Substation Power Transformers.

Transformer	Voltage	Summer Capacity Normal Limit (MVA)	Summer Capacity LTE Limit (MVA)	Winter Capacity Normal Limit (MVA)	Winter Capacity LTE Limit (MVA)
1T1 Beech Street	67.7 - 13.8 kV	26.77	28.24	30.12	33.16
11T1 Canton Street (13.8 kV)	67.7 - 13.8 kV	17.46	20.22	19.71	23.38
11T2 Canton Street (4.16 kV)	67.725 - 4.16 kV	3.56	3.94	4.11	4.74
Flagg Pond Auto #1	115 - 69 kV	115.64	135.99	130.52	150.00
Flagg Pond Auto #2	115 - 69 kV	121.5	139.18	136.83	161.8
Flagg Pond Auto (30 MVA Spare)	115 - 69 kV	58.72	63.18	65.82	74.07
Flagg Pond Auto (24 MVA Spare)	115 - 69 kV	43.06	51.31	49.51	59.52
30T1 Lunenburg	67.7 - 13.8 kV	13.68	13.81	15.42	16.26
31T1 Pleasant Street (13.8 kV)	67.725 - 13.8 kV	15.98	18.8	18.05	21.43
31T2 Pleasant Street (4.16 kV)	64.5 - 4.16 kV	3.56	3.94	4.11	4.74
50T2 Princeton Road	67.725 - 13.8 kV	26.36	28.39	31.47	35.07
50T3 Princeton Road	67.725 - 13.8 kV	23.97	27.28	26.53	31.52
25T1 River Street	67.725 - 13.8 kV	18.56	19.94	22.29	24.79
22T1 Sawyer Passway	67.725 - 13.8 kV	24.17	27.90	28.73	33.97
22T2 Sawyer Passway	67.725 - 13.8 kV	24.17	27.90	28.73	33.98
40T1 Summer Street	67.725 - 13.8 kV	35*		•	
15T1 Townsend	66.1 - 13.8 kV	12.46	14.1	14.05	16.57
39T1 West Townsend	67.725 - 13.8 kV	13.67	15.65	16.45	19.52
15 MVA Mobile	64.5 - 13.8 kV	15.00	15.00	15.00	15.00

* - Present top nameplate rating (FA/FA 65).

APPENDIX D

LOAD HISTORY AND DESIGN FORECASTS

1 LOAD HISTORY

This past summer, the FG&E system reached a new three-year ratchet peak of 97.978 MW demand load on August 14, 2002 at 2:00 PM. Load at the Mill 8 paper plant during this time was 8.09 MW. Linear trending analysis for FG&E summer peak demands for the thirty three year history back to 1970 (with the Mill 8 load excluded) shows a growth rate of 0.90 MW per year, on average, with a standard error of +/ 5.20 MW. The maximum positive variation from the calculated trend line (with the Mill 8 load excluded) was 12.76 MW, which occurred with the 1978 summer peak.

This winter, the FG&E system reached a new three-year ratchet peak of 90.011 MW demand load on January 22, 2003 at 7:00 PM. Load at the Mill 8 paper plant during this time was 7.988 MW. Linear trending analysis for FG&E winter peak demands for the thirty-four year history back to 1969/70 (with the Mill 8 load excluded) shows a growth rate of 0.71 MW per year, on average, with a standard error of +/- 4.07 MW. The maximum positive variation from the calculated trend line (with the Mill 8 load excluded) was 7.64 MW, which occurred with the 1979/80 winter peak.

2 DESIGN FORECASTS

The following tables provide the present ten-year design load forecasts for the FG&E operating system. Separate forecasts are provided for the summer and winter seasons, and two design load levels are established for each – *Peak Design Load* and *Extreme Peak Load.* Each forecast is based on the system's most recent three-year "ratchet" peak and the linear trends of its past peak load history. The three-year "ratchet" peak represents the highest peak load reached for that system within the most recent three years, and is used as the base point for forward projections. Linear trending analysis of the peak load history establishes the rate of growth used for projecting forward. This linear analysis also identifies a standard error and maximum error from the historical trend line. These are used in the forward projections to provide design margins against year-to-year variability and other uncertainties.

Each forecast is based on the system's most recent three-year "ratchet" peak and the linear trends of its past peak load history. The three-year "ratchet" peak represents the highest peak load reached for that system within the most recent three years, and is used as the base point for forward projections. Linear trending analysis of the peak load history establishes the rate of growth used for projecting forward. This linear analysis also identifies a standard error and maximum error from the historical trend line. These are used in the forward projections to provide design margins against year-to-year variability and other uncertainties.

Table 1. FG&E Ten-Year Summer Design Forecasts

Projected Summer Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2004	106.9	114.4
2005	107.8	115.3
2006	108.7	116.2
2007	109.6	117.2
2008	110.5	118.1
2009	111.4	119.0
2010	112.3	119.9
2011	113.2	120.8
2012	114.1	121.7
2013	115.0	122.6

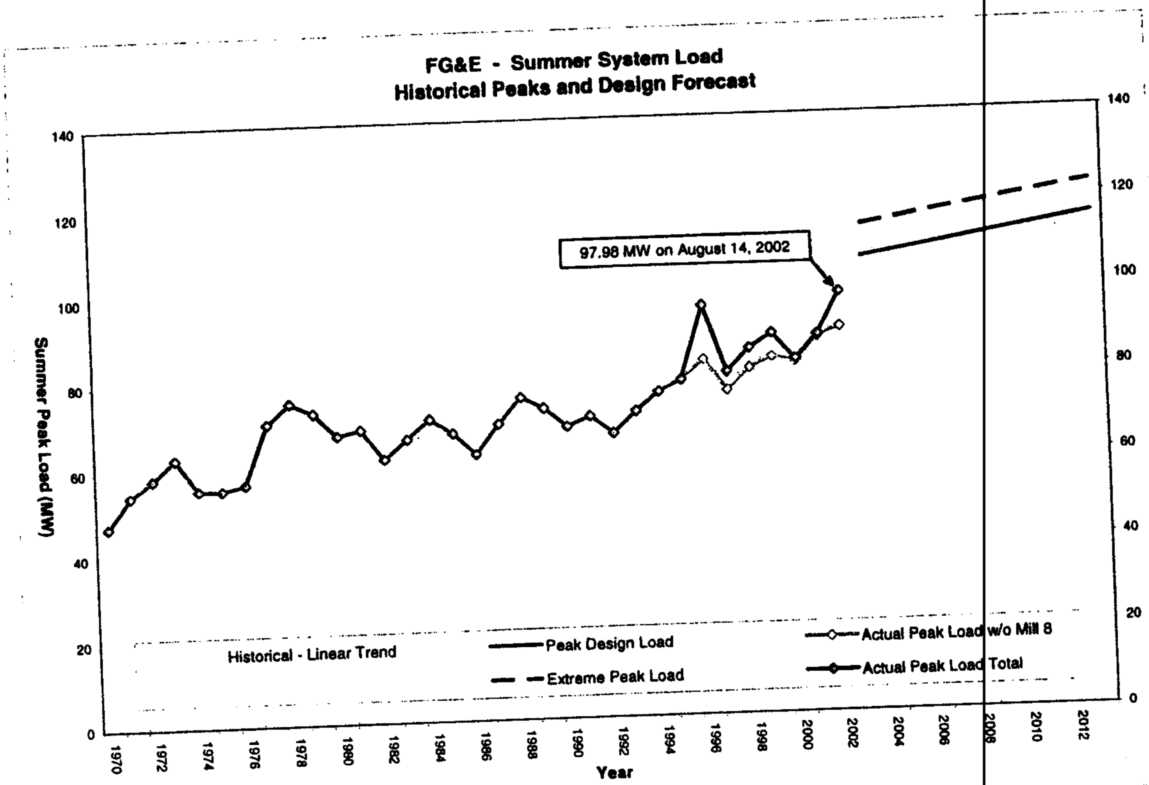
Table 2. FG&E Ten-Year Winter Design Forecasts

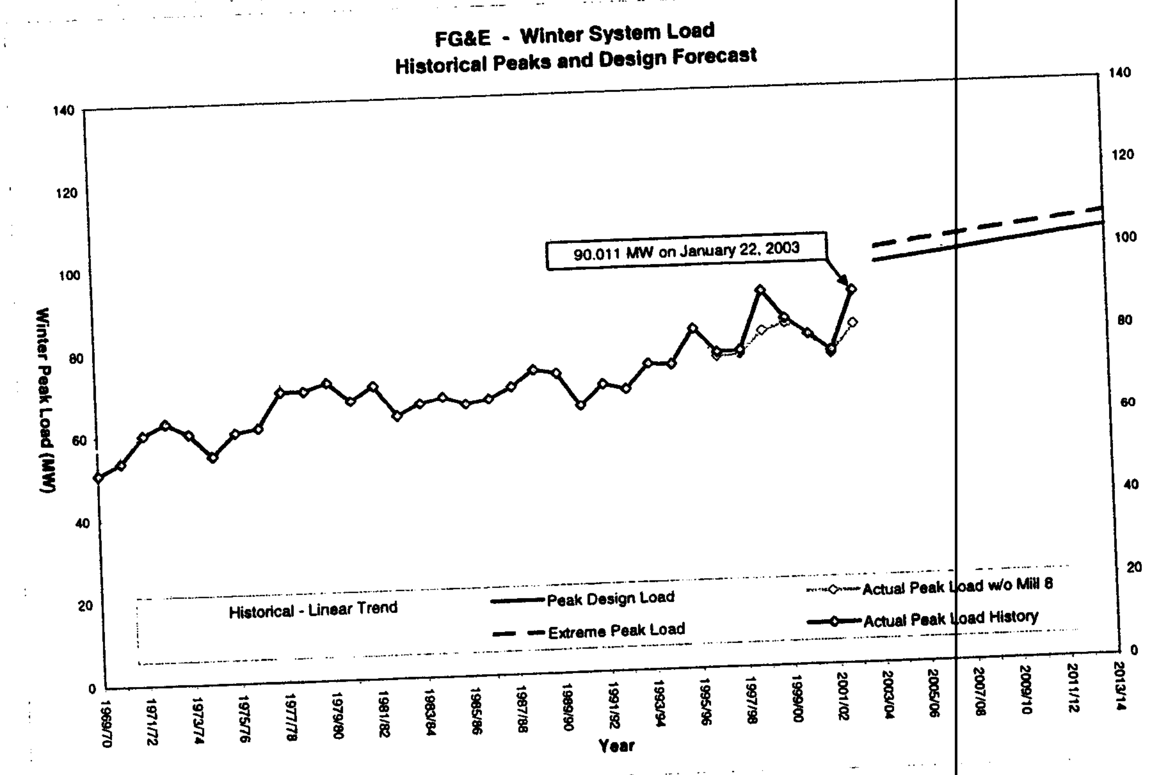
Projected Winter Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2004/05	97.5	101.1
2005/06	98.2	101.8
2006/07	98.9	102.5
2007/08	99.6	103.2
2008/09	100.3	103.9
2009/10	101.1	104.6
2010/11	101.8	105.3
2011/12	102.5	106.0
2012/13	103.2	106.8
2013/14	103.9	107.5

Contingency studies for the loss of major system elements are evaluated against *Peak Design Load* levels to identify where and when system constraints do not meet planning guidelines. *Peak Design Load* projections are derived by adding one (1) standard error to the otherwise unadjusted linear projection. This adjustment is to account for routine weather related variations and other forecasting uncertainties.

More demanding *Extreme Peak Load* levels are used for evaluation of system constraints under the highest conceivable load conditions, but without the loss of major equipment. *Extreme Peak Load* projections are derived by adding the maximum error to the otherwise unadjusted linear projection. This maximum error is determined as the largest positive deviation between each peak in the historical data versus the calculated trend line. Under these extreme peak load conditions it is essential that the system, with all major elements in service, meet planning guidelines while serving all customers.

Note that the load at Mill 8 is handled separately from the rest of the FG&E system loads in determining historical trends and future projections. Since new operations at Mill 8 got underway in 1996, load there has been erratic due to multiple shutdowns and restarts following the financial ups and downs of the various operators. At its highest level, this load has represented as much as 15% of the total FG&E system load. Recognizing that the relative size and volatility of the Mill 8 load has an unrepresentative impact on the linear trending analysis for the FG&E system load as a whole, it has been excluded from the historical trending and added back into forward projections as an independent quantity. For this purpose, a fixed load of 10 MW was used in both the summer and winter forecasts. This represents the best estimate of the anticipated load at this facility as it reaches full operation.


FG&E - Summer System Load
Historical Peaks and Design Forecast
97.98 MW on August 14, 2002
Summer Peak Load (MW)
Year
Historical - Linear Trend
Peak Design Load
Extreme Peak Load
Actual Peak Load w/o Mill 8
Actual Peak Load Total


FG&E - Winter System Load
Historical Peaks and Design Forecast
90.011 MW on January 22, 2003
Winter Peak Load (MW)
Year
Historical - Linear Trend
Peak Design Load
Extreme Peak Load
Actual Peak Load w/o Mill 8
Actual Peak Load History

APPENDIX E

BASE CASE STUDIES

The information provided in this section describes details of power flow simulation results for year by year studies of the FG&E system in its normal or proposed operating configuration(s). The system is examined for deficiencies under peak design and extreme peak loading conditions with all elements in service. Details are quantified as to the adequacy of the normal system operating configuration, and substation and subtransmission system infrastructure. System voltages or equipment loadings that are approaching operational limits are noted.

Unless otherwise noted, the system is modeled in its normal operating configuration, summarized as follows:

<u>01 Line, Flagg Pond to Summer Street</u>

- 01/113 switch normally open at Princeton Road
- 01/102 switch normally open at River Street
- 160 breaker normally open at Beech Street
- Distribution loads normally supplied:
  - 11T1 at Canton Street S/S (13.8 kV), including circuits 11W11
  - 11T2 at Canton Street S/S (4.16 kV), including circuits 11H10 and 11W11

<u>02 Line, Flagg Pond to Summer Street</u>

- 02/110 switch normally open at Canton Street
- Distribution loads normally supplied:
  - 1T1 at Beech Street S/S, including Beech Street circuits 1W1, 1W2, 1W4 and 1W6, Wallace Road circuit 21W16, and Rindge Road circuits 35H35, 35H36 and 21W36

<u>03 Line, Flagg Pond to River Street and Princeton Road</u>

- Distribution loads normally supplied:
  - 25T1 at River Street S/S, including circuits 25W27, 25W28 and 25W29
  - 50T2 at Princeton Road S/S, including circuits 50W53 and 50W54
  - 50T3 at Princeton Road S/S, including circuits 50W51, 50W55 and 50W56

<u>06 Line, Summer Street to Sawyer Passway</u>

- Distribution loads normally supplied:
  - 22T1 at Sawyer Passway S/S, including Sawyer Passway circuits 22W1, 22W2, 22W3 and 22W17, and Nockege circuit 20W42
  - 22T2 at Sawyer Passway S/S, including Sawyer Passway circuits 22W8, 22W10 and 22W11, and Nockege circuits 20H22, 20H24 and 20W24

<u>08 Line, Summer Street to Townsend</u>

- Distribution loads normally supplied:
  - 31T2 at Pleasant Street S/S (4.16 kV), including circuit 31H34
  - 30T1 at Lunenburg S/S, including circuits 30W30 and 30W31
  - 15T1 at Townsend S/S, including circuits 15W15, 15W16 and 15W17

<u>09 Line, Summer Street to West Townsend</u>

- 09/112 switch normally open at Pleasant Street
- 09/130 switch normally open at Lunenburg
- 09/203 breaker normally open at West Townsend
- Distribution loads normally supplied:
  - 31T1 at Pleasant Street S/S (13.8 kV), including circuits 31W37 and 31W38
  - 39T1 at WestTownsend S/S, including circuit s 39W18 and 39W19

<u>010 Line, Townsend to West Townsend</u>

- 010/100 switch normally open at Townsend
- 010/110 switch normally open at West Townsend

<u>1303 Line, Summer Street to Sawyer Passway</u>

- 1303/203 breaker normally open at Sawyer Passway

<u>1309 Line, Summer Street to Sawyer Passway</u>

- 1309/203 breaker normally open at Sawyer Passway

Additionally, the following system capacitor banks are modeled as being switched in:

• Beech Street S/S	1.2 MVAr (13.8 kV)
• Townsend S/S	1.2 MVAr (13.8 kV)
• River Street S/S	1.2 MVAr (13.8 kV)
• Pleasant Street S/S	1.2 MVAr (13.8 kV)
• Rindge Road S/S	0.3 MVAr (4.16 kV, modeled at 13.8 kV)
• Summer Street S/S (40C2)	3.6 MVAr (13.8 kV)
• Sawyer Passway S/S (22C1)	3.6 MVAr (13.8 kV)
• Sawyer Passway S/S (22C2)	3.6 MVAr (13.8 kV)
• Princeton Road circuit 50W51	1.2 MVAr (13.8 kV)

Other capacitors on distribution circuits are typically not directly modeled, but rather are included within modeled loads.

1 Base Case Studies – Peak Design Loads

Described here are "base case" conditions observed from power flow simulations analyzing the FG&E system model in its normal configuration with no major elements out of service.

1.1 Summer 2004 – 106.9 MW Peak Design Load

The following power flow simulation results are observed when modeling the FG&E system at a peak design level of 106.9 MW (load and losses) for the summer of 2004:

1.1.1 w/ Pinetree generation on line

- System loads and losses:

	MW	MVAr
distribution load	105.1	25.9
station capacitors		-18.1
transmission/substransmission losses	1.8	12.9
total system load	106.9	20.8

- System supplies:

	MW	MVAr
Flagg Pond 115 kV import	92.0	17.0
Pinetree generation 69 kV import	14.9	3.8
total system supply	106.9	20.8

- System power factor: 0.982, lagging

- Flagg Pond No.1 autotransformer at 47.2 MVA (41% of Normal limit)
- Flagg Pond No.2 autotransformer at 45.6 MVA (38% of Normal limit)

- 01 Line, Flagg Pond to Canton Street, 556 ACSR at 304 A (41% of Normal limit)
- 02 Line, Flagg Pond to Beech Street Tap, 556 ACSR at 371 A (50% of Normal limit)
- 03 Line, Flagg Pond to Princeton Road Tap, 556 ACSR at 261 A (35% of Normal limit)
- 06 Line, Summer Street to Sawyer Passway, 336 AA at 118 A (22% of Normal limit)
- 08 Line, Summer Street to Pleasant Street, 1/0 ACSR at 199 A (81% of Normal limit)
- 09 Line, Summer Street to Pleasant Street, 1/0 ACSR at 135 A (55% of Normal limit)

- Flagg Pond 115 kV at 98% voltage
- Flagg Pond 69 kV at 97% voltage
- Summer Street 69 kV at 96% voltage
- Townsend 69 kV at 93% voltage
- West Townsend 69 kV at 95% voltage

1.1.2 w/ Pinetree generation out of service

- System loads and losses:

	MW	MVAr
distribution load	105.1	25.9
station capacitors		-17.9
transmission/substransmission losses	1.8	14.4
total system load	106.9	22.4

- System supplies:

	MW	MVAr
Flagg Pond 115 kV import	106.9	22.4
Pinetree generation 69 kV import	-	-
total system supply	106.9	22.4

- System power factor: 0.979, lagging

- Flagg Pond No.1 autotransformer at 55.1 MVA (48% of Normal limit)
- Flagg Pond No.2 autotransformer at 53.2 MVA (44% of Normal limit)

- 01 Line, Flagg Pond to Canton Street, 556 ACSR at 307 A (41% of Normal limit)
- 02 Line, Flagg Pond to Beech Street Tap, 556 ACSR at 374 A (50% of Normal limit)
- 03 Line, Flagg Pond to Princeton Road Tap, 556 ACSR at 262 A (35% of Normal limit)
- 06 Line, Summer Street to Sawyer Passway, 336 AA at 119 A (24% of Normal limit)
- 08 Line, Summer Street to Pleasant Street, 1/0 ACSR at 201 A (81% of Normal limit)
- 09 Line, Summer Street to Pleasant Street, 1/0 ACSR at 136 A (55% of Normal limit)

- Flagg Pond 115 kV at 97% voltage
- Flagg Pond 69 kV at 96% voltage
- Summer Street 69 kV at 96% voltage
- Townsend 69 kV at 92% voltage
- West Townsend 69 kV at 95% voltage

1.2 Future Years

Significant conditions or changes from the 2004 – 106.9 MW base model are noted in the following sections.

1.2.1 Summer 2010 – 112.3 MW Peak Design Load w/ Pinetree generation out of service

* - Townsend 69 kV at 90% voltage
* - Townsend 13.8 kV at 97.5% voltage

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

1.2.2 Summer 2012 – 114.1 MW Peak Design Load w/ Pinetree generation on line

* - Townsend 69 kV at 89.5% voltage
* - Townsend 13.8 kV at 97.1% voltage

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2 Base Case Studies – Extreme Peak Loads

Described here are conditions observed from power flow simulations analyzing the FG&E system model at *Extreme Peak* load levels. In each case, the system is in its normal configuration with no major elements out of service.

2.1 Summer 2004 – 114.4 MW Extreme Peak Load

The following power flow simulation results are observed when modeling the FG&E system at an extreme peak load level of 114.4 MW (load and losses) for the summer of 2004:

2.1.1 w/ Pinetree generation on line

- System loads and losses:

	MW	MVAr
distribution load	112.3	27.6
station capacitors		-18.2
transmission/substransmission losses	2.1	15.6
total system load	114.4	25.0

- System supplies:

	MW	MVAr
Flagg Pond 115 kV import	99.5	21.3
Pinetree generation 69 kV import	14.9	3.7
total system supply	114.4	25.0

- System power factor: 0.977, lagging

- Flagg Pond No.1 autotransformer at 51.3 MVA (44% of Normal limit)
- Flagg Pond No.2 autotransformer at 49.5 MVA (41% of Normal limit)

- 01 Line, Flagg Pond to Canton Street, 556 ACSR at 340 A (45% of Normal limit)
- 02 Line, Flagg Pond to Beech Street Tap, 556 ACSR at 414 A (55% of Normal limit)
- 03 Line, Flagg Pond to Princeton Road Tap, 556 ACSR at 283 A (38% of Normal limit)
- 06 Line, Summer Street to Sawyer Passway, 336 AA at 130 A (24% of Normal limit)
- 08 Line, Summer Street to Pleasant Street, 1/0 ACSR at 225 A (91% of Normal limit)
- 09 Line, Summer Street to Pleasant Street, 1/0 ACSR at 150 A (61% of Normal limit)

- Flagg Pond 115 kV at 95% voltage
- Flagg Pond 69 kV at 94% voltage
- Summer Street 69 kV at 93% voltage
- * - Townsend 69 kV at 89.5% voltage
- * - Townsend 13.8 kV at 97.0% voltage
- West Townsend 69 kV at 92% voltage

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2.1.2 w/ Pinetree generation out of service

- System loads and losses:

	MW	MVAr
distribution load	112.3	27.6
station capacitors		-17.9
transmission/substransmission losses	2.2	17.3
total system load	114.5	27.0

- System supplies:

	MW	MVAr
Flagg Pond 115 kV import	114.5	27.0
Pinetree generation 69 kV import	-	-
total system supply	114.5	27.0

- System power factor: 0.973, lagging

- Flagg Pond No.1 autotransformer at 59.1 MVA (51% of Normal limit)
- Flagg Pond No.2 autotransformer at 57.1 MVA (47% of Normal limit)

- 01 Line, Flagg Pond to Canton Street, 556 ACSR at 343 A (46% of Normal limit)
- 02 Line, Flagg Pond to Beech Street Tap, 556 ACSR at 418 A (56% of Normal limit)
- 03 Line, Flagg Pond to Princeton Road Tap, 556 ACSR at 286 A (38% of Normal limit)
- 06 Line, Summer Street to Sawyer Passway, 336 AA at 131 A (25% of Normal limit)
- 08 Line, Summer Street to Pleasant Street, 1/0 ACSR at 228 A (92% of Normal limit)
- 09 Line, Summer Street to Pleasant Street, 1/0 ACSR at 152 A (61% of Normal limit)

- Flagg Pond 115 kV at 94% voltage
- Flagg Pond 69 kV at 93% voltage
- Summer Street 69 kV at 92% voltage
- * - Townsend 69 kV at 88.6% voltage
- * - Townsend 13.8 kV at 95.9% voltage
- West Townsend 69 kV at 91% voltage

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2.2 Future Years

Significant conditions or changes from the 2004 – 114.4 MW extreme peak model are noted in the following sections.

2.2.1 Summer 2005 – 115.3 MW Peak Design Load w/ Pinetree generation out of service

* - Lunenburg 69 kV at 89.8% voltage (08 Line side)

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2.2.2 Summer 2006 – 116.2 MW Peak Design Load w/ Pinetree generation on line

* - Lunenburg 69 kV at 89.9% voltage (08 Line side)

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2.2.3 Summer 2006 – 116.2 MW Peak Design Load w/ Pinetree generation out of service

* - West Townsend 69 kV at 89.8% voltage
* - Lunenburg 13.8 kV at 97.3% voltage

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2.2.4 Summer 2007 – 117.2 MW Peak Design Load w/ Pinetree generation out of service

* - Pleasant Street 69 kV at 90% voltage (08 Line side)
* - Pleasant Street 69 kV at 90% voltage (09 Line side)
* - Lunenburg 69 kV at 89.6% voltage (09 Line side)

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

2.2.5 Summer 2008 – 118.1 MW Peak Design Load w/ Pinetree generation on line

* - West Townsend 69 kV at 89.9% voltage
* - Lunenburg 13.8 kV at 97.3% voltage

* *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

From 2009 forward, conditions continue to deteriorate.

APPENDIX F

CONTINGENCY SWITCHING STUDIES

The information provided in this section describes the power flow simulation results for the case by case studies of loss of system elements at peak load conditions. These details are provided to quantify the adequacy of substation and subtransmission system infrastructure under contingency circumstances, and to guide development of operating procedures to respond to these scenarios. System voltages or equipment loadings that are approaching operational limits are described for each significant switching step. Details regarding troubleshooting faults or isolation of specific components to be left out of service are not typically provided. Similarly, not all details that would be required in formal switching orders are included.

The following is a summary list of the loss-of-element contingencies studied:

1) Loss of I-135S Line, Pratts Junction to Flagg Pond
2) Loss of J-136S Line at Pratts Junction
3) Loss of I-135S and J-136S Lines, Pratts Junction to Flagg Pond (double circuit tower)
4) Loss of I-135N Line at Flagg Pond
5) Loss of J-136N Line at Flagg Pond
6) Loss of I-135N and J-136N Lines, Bellows Falls to Flagg Pond (double circuit tower)
7) Loss of Flagg Pond No.1 Autotransformer
8) Loss of Flagg Pond No.2 Autotransformer
9) Loss of 01 Line at Flagg Pond
10) Loss of 02 Line at Flagg Pond
11) Loss of 03 Line at Flagg Pond
12) Loss of 06 Line, Summer Street to Sawyer Passway
13) Loss of 08 Line at Summer Street
14) Loss of 09 Line at Summer Street
15) Loss of Beech Street Transformer
16) Loss of 1W1 Circuit at Beech Street
17) Loss of 1W1 Circuit at Wallace Road
18) Loss of 21F41 Feeder, Wallace Road to Rindge Road
19) Loss of Sawyer Passway 22T1 Transformer
20) Loss of Sawyer Passway 22T2 Transformer
21) Loss of 22W10 Circuit at Sawyer Passway
22) Loss of 22W17 Circuit at Sawyer Passway
23) Loss of Summer Street Transformer
24) Loss of 40W39 Circuit at Summer Street

For each element scenario, the system was reviewed only under the assumed worst circumstances for the location of the loss of equipment. For example, the loss of the 01 Line is only studied for trouble at the Flagg Pond end. Loss of the 01 Line at other ends, such as Summer Street, are not detailed because they are assumed to be less severe. Furthermore, the switching examined may in some cases set up a configuration that appears to re-energize a faulted element or ignore a lack of sectionalizing. As a study of system capabilities, the emphasis is on performance in contingency configurations, and not maintenance switching or emergency troubleshooting. Finally, the switching examined may not be the only contingency response available.

1 Summer 2004 – 106.9 MW

The contingencies described here are studied at a FG&E system design level of 106.9 MW for the summer of 2004, using the base case model described in the Base Case Studies section. No proposed system improvements are included unless specifically noted. In each case, the following non-utility generation is modeled as being off-line:

- Pinetree Power

1) Loss of I-135S Line, Pratts Junction to Flagg Pond
(I-135 open at Pratts Junction, 8B2 and 8B3 open at Flagg Pond)
   - No switching necessary
   - I-135S Line, Pratts Junction to Litchfield Street Tap, at 115 MVA (99% of Normal limit)
   - 08 Line: Townsend 69 kV at 91% voltage

2) Loss of J-136S Line at Pratts Junction
(J-136 open at Pratts Junction, Flagg Pond supplying Litchfield Street Tap)
   - No switching necessary
   - I-135S Line, Pratts Junction to Flagg Pond, at 111 MVA (95% of Normal limit)
   - 08 Line: Townsend 69 kV at 90% voltage

3) Loss of I-135S and J-136S Lines, Pratts Junction to Flagg Pond (double circuit tower)
(I-135 and J-136 open at Pratts Junction; 8A2, 8A3, 8B2, 8B3 open at Flagg Pond)

   * *Non-convergent simulation results. See sections detailing this constraint and recommendations.*

4) Loss of I-135N Line at Flagg Pond
(8B1 and 8B2 open at Flagg Pond)
   - No switching necessary

5) Loss of J-136N Line at Flagg Pond
(8A1 and 8A2 open at Flagg Pond)
   - No switching necessary

6) Loss of I-135N and J-136N Lines, Bellows Falls to Flagg Pond (double circuit tower)
(135 and 136 open at Bellows Falls; 8A1, 8A2, 8B1 and 8B2 open at Flagg Pond; I-1350 open at Monadnock)
- No switching necessary

7) Loss of Flagg Pond No.1 Autotransformer (4T1 out of service)
- No switching necessary
- Flagg Pond No.2 autotransformer at 108 MVA (89% of Normal limit)
- 08 Line: Townsend 69 kV at 91% voltage

8) Loss of Flagg Pond No.2 Autotransformer (4T2 out of service)
- No switching necessary
- Flagg Pond No.1 autotransformer at 108 MVA (94% of Normal limit)

9) Loss of 01 Line at Flagg Pond
(7B2 and 7B3 open at Flagg Pond, Canton Street supplied on 01 Line from Summer Street)
- No switching necessary
- 02 Line, Flagg Pond to Beech Street Tap, 556 ACSR at 687 A (92% of Normal limit)
- 08 Line: Townsend 69 kV at 91% voltage

10) Loss of 02 Line at Flagg Pond
(7A2 and 7A3 open at Flagg Pond, Beech Street supplied on 02 Line from Summer Street)
- No switching necessary
- 01 Line, Flagg Pond to Canton Street, 556 ACSR at 690 A (92% of Normal limit)
- 08 Line: Townsend 69 kV at 91% voltage

11) Loss of 03 Line at Flagg Pond (7B1 and 7B2 open at Flagg Pond)
- 29 MW of load out of service on Princeton Road circuits 50W51, 50W53, 50W54, 50W55 and 50W56, and River Street circuits 25W27, 25W28 and 25W29

1. Princeton Road S/S – open 03/110 switch
2. Princeton Road S/S – close 01/113 switch
   - 19 MW of load restored on Princeton Road circuits 50W51, 50W53, 50W54, 50W55 and 50W56
3. River Street S/S – open 03/102 switch
4. River Street S/S – close 01/102 switch
   - 10 MW of load restored on River Street circuits 25W27, 25W28 and 25W29
   - All load restored
   - 01 Line, Flagg Pond to River Street Tap, 556 ACSR at 558 A (75% of Normal limit)

12) Loss of 06 Line, Summer Street to Sawyer Passway (06/103 open at Summer Street)
- 13 MW of load out of service on circuits 22W1, 22W2, 22W3, 22W8, 22W10, 22W11 and 22W17, including Nockege circuits 20H22, 20H23, 20H24, 20W24 and 20W42

1. Sawyer Passway S/S – close 1303/203 breaker
   - All load restored
   - 1303 Line, Summer Street to Sawyer Passway, 477 AA at 559 A (84% of Normal limit)
   - Summer Street 40T1 transformer at 23 MVA (83% of 38 MVA top nameplate rating)
2. Sawyer Passway S/S – close 1309/203 breaker

13) Loss of 08 Line at Summer Street (08/103 open at Summer Street)
- 21 MW of load out of service on Pleasant Street circuit 31H34, Lunenburg circuits 30W30 and 30W31, and Townsend circuits 15W15, 15W16 and 15W17

1. Pleasant Street S/S – open 08/110 switch
2. Pleasant Street S/S – close 09/112 switch
   - 3 MW of load restored on Pleasant Street circuit 31H34
3. Lunenburg S/S – open 08/130 switch
4. Lunenburg S/S – close 09/130 switch
   - 9 MW of load restored on Lunenburg circuits 30W30 and 30W31
   - 09 Line, Summer Street to Pleasant Street, 1/0 ACSR at 237 A (96% of Normal limit)
5. Townsend S/S – open 08/203 breaker
6. Townsend S/S – open 08/120 switch
7. Townsend S/S – close 010/100 switch
8. West Townsend S/S – close 09/203 breaker
   - 9 MW of load restored on Townsend circuits 15W15, 15W16 and 15W17
   - All load restored

   * - 09 Line, Summer Street to Pleasant Street, 1/0 ACSR at 340 A (138% of Normal limit, 116% of LTE limit)
   - 09 Line, Pleasant Street to Lunenburg, 1/0 ACSR at 240 A (86% of Normal limit)
   - 010 Line: Townsend 69 kV at 90% voltage

   * *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

14) Loss of 09 Line at Summer Street (09/103 open at Summer Street)
- 15 MVA of load out of service on Pleasant Street circuits 31W37 and 31W38, and West Townsend circuits 39W18 and 39W19

1. Pleasant Street S/S – open 09/110 switch

2. Pleasant Street S/S – close 09/112 switch
   - 12 MW of load restored on Pleasant Street circuits 31W37 and 31W38
   * - 08 Line, Summer Street to Pleasant Street, 1/0 ACSR at 305 A (124% of Normal limit, 104% of LTE limit)
3. Townsend S/S – open 08/203 breaker
4. West Townsend S/S – open 09/120 switch
5. West Townsend S/S – close 010/110 switch
6. Townsend S/S – close 08/203 breaker
   - 3 MW of load restored on West Townsend circuits 39W18 and 39W19
   - All load restored
   * - 08 Line, Summer Street to Pleasant Street, 1/0 ACSR at 338 A (137% of Normal limit, 115% of LTE limit)
   - 08 Line, Pleasant Street to Lunenburg, 1/0 ACSR at 208 A (84% of Normal limit)
   - 010 Line: West Townsend 69 kV at 91% voltage

   * *Does not meet design guidelines. See sections detailing this constraint and recommendations.*

15) Loss of Beech Street Transformer (Beech Street 1T1 out of service)
   - 11 MW of load out of service on Beech Street circuits 1W1, 1W2, 1W4 and 1W6, Wallace Road circuit 21W16, and Rindge Road circuits 35H35, 35H36 and 21W36

1. Beech Street S/S – open 2/103 breaker
2. Beech Street S/S – open 6/103 breaker
3. Wallace Road S/S – open 1/103 breaker
4. Nockege S/S – close 1A/113 breaker
   - 4 MW of load restored on Beech Street circuits 1W1 and 1W4
   - 22W10 Circuit, Sawyer Passway to Nockege, 350 Cu at 324 A (74% of Normal limit)
   - 1W1 Circuit, Nockege to Kimball St., 4/0 Cu at 161 A (32% of Normal limit)
5. p.1578 Oak Hill Rd. – close tie switch to circuit 25W28
   - 3 MW of load restored on Beech Street circuit 1W2
   - River Street 25T1 transformer at 13 MVA (70% of Normal limit)
   - 25W28 Circuit at River Street, 500 Cu at 347 A (66% of Normal limit)
6. Rollstone St. – close 8-115 switch
   - 3 MW of load restored on Wallace Road circuit 21W16, and Rindge Road circuits 35H35, 35H36 and 21W36
   - 22W1 Circuit at Sawyer Passway, 336 AA Spacer at 296 A (68% of Normal limit)
7. p.604 Fifth Mass. Tpk. – close tie switch to circuit 50W55
   - 2 MW of load restored on Beech Street circuit 1W6
   - All load restored

Note: The above review involves use of distribution circuit ties for load restoration. Details are given assessing substation and substransmission system adequacy. Further details on distribution system performance are beyond the precision of the modelling, and should be reviewed in further detail.

16) Loss of 1W1 Circuit at Beech Street (1/103 open at Beech Street)
- 4 MW of load out of service on Beech Street circuit 1W1, Wallace Road circuit 21W16, and Rindge Road circuits 35H35, 35H36 and 21W36

1. Nockege S/S – close 1A/113 breaker
   - All load restored
   - 22W10 Circuit, Sawyer Passway to Nockege, 350 Cu at 319 A (73% of Normal limit)
   - 1W1 Circuit, Nockege to Kimball St., 4/0 Cu at 154 A (31% of Normal limit)
   - Rindge Road 13.8 kV at 96% voltage

17) Loss of 1W1 Circuit at Wallace Road (1/103 open at Wallace Road)
- 3 MW of load out of service on Wallace Road circuit 21W16, and Rindge Road circuits 35H35, 35H36 and 21W36

1. Rollstone St. – close 8-115 switch
   - All load restored
   - 22W1 Circuit at Sawyer Passway, 336 AA Spacer at 296 A (68% of Normal limit)

18) Loss of 21F41 Feeder, Wallace Road to Rindge Road (41/103 open at Wallace Road)
- 3 MW of load out of service on Rindge Road circuits 35H35, 35H36 and 21W36
- No switching available

19) Loss of Sawyer Passway 22T1 Transformer
- No switching necessary
- Sawyer Passway 22T2 transformer at 14 MVA (57% of Normal limit)

20) Loss of Sawyer Passway 22T2 Transformer
- No switching necessary
- Sawyer Passway 22T1 transformer at 14 MVA (57% of Normal limit)

21) Loss of 22W10 Circuit at Sawyer Passway (22W10/203 open at Sawyer Passway)
- 4 MW of load out of service on 22W10 circuit, including Nockege circuits 20H22, 20H23, 20H24 and 20W24

1. Nockege S/S - close B/173 bus tie breaker
   - All load restored
   - 22W17 Circuit at Sawyer Passway, 336 AA Spacer at 210 A (48% of Normal limit)

22) Loss of 22W17 Circuit at Sawyer Passway (22W17/203 open at Sawyer Passway)
- 1 MW of load out of service on 22W17 circuit, including Nockege 20W42 circuit

1. Nockege S/S - close B/173 bus tie breaker
   - All load restored
   - 22W10 Circuit at Sawyer Passway, 336 AA Spacer at 210 A (48% of Normal limit)

23) Loss of Summer Street Transformer (Summer Street 40T1 out)
- 9 MW of load out of service on circuits 40W38, 40W39 and 40W40, including South Fitchburg circuits 5H6 and 5H12

1. Sawyer Passway S/S – close 1303/203 breaker
   - All load restored
   - 1303 Line, Summer Street to Sawyer Passway, 477 AA at 386 A (58% of Normal limit)
2. Sawyer Passway S/S – close 1309/203 breaker
   - 1303 Line, Summer Street to Sawyer Passway, 477 AA at 226 A (34% of Normal limit)
   - 1309 Line, Summer Street to Sawyer Passway, 336 AA at 160 A (28% of Normal limit)

24) Loss of 40W39 Circuit at Summer Street (39/103 open at Summer Street)
- 5 MW of load out of service on circuit 40W39, including South Fitchburg circuits 5H6 and 5H12
- Possible distribution switching solutions exist to restore all load, for which substation and subtransmission systems appear adequate to support.

APPENDIX G

REFERENCES

1. Electric System Planning Guide. Unitil Service Corp. April, 2000

2. Electrical Equipment Rating Procedures. Unitil Service Corp. rev. 1.0. April 4, 2000

3. Economic Evaluation Procedures. Unitil Service Corp. rev. 1.0. April 24, 2000

APPENDIX H

DIAGRAMS

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

LOADFLOW PLOT

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

ATTACHMENT 2

FG&E ELECTRIC DISTRIBUTION PLANNING EVALUATION

Unitil Service Corp.

Fitchburg Gas and Electric Light Company

Distribution System Planning Evaluation 2004-2008

Prepared By:

Jamie Goudreault
Unitil Service Corp
August 8th, 2003

TABLE OF CONTENTS

1 Executive Summary

The peak load of the FG&E system has grown from 66 MW in 1992 to 98 MW in 2002. The reason for the load increase is twofold: 1) Large customer addition – 9MW and 2) load growth – 23 MW. The load growth resulting in the 23 MW of load increase is directly correlated an exceptional residential housing market and expanding businesses.

The purpose of this study was to identify any necessary electrical distribution system improvements through the year 2008, and to propose the most cost-effective solutions. All cost estimates included in this study are shown without overheads.

The following items will require action within the 5-year study period. Cost estimates were developed by Operations. All cost estimates provided in this report are without overheads.

Year	Project Description	Justification	Cost (Estimated)
2004	Townsend S/S Transformer: Load Relief	Overload – 90% of rating	$3,000
2004	Rindge Road S/S Transformer: Load Relief	Voltage (112V) / Overload (92%)	$45,178
2004	Circuit 20H24: Change CT Ratio	Overload – 90% of nameplate	$1,000
2004	Circuit 39W18: Change CT Ratio	Overload – 92% of nameplate	$2,000
2004	Circuit 01W04: Walnut St Load Balance	Overload – 141% of nameplate	$1,000
2004	Circuit 05H12 Load Transfer	Low Voltage – 113 volts	$15,947
2004	Circuit Load Balancing	Imbalance > 20%	$2,400
2004	Circuit 01W04: Re-conductor Phase 2	Condition replacement	$201,332
2005	Circuit 21W36: Replace Kinsman Rd Step	Overload – 126% of nameplate	$5,500
2006	Pleasant Street S/S Transformer: Load Relief	Overload – 91% of rating	$TBD
2007	Circuit 50W55: Bypass Fuse Modification	Overload – 92% of rating	$3,000

2 System Configuration

The FG&E system takes service off of National Grid's 135 and 136 lines at Flagg Pond. A 115 kV ring bus serves two 100 MVA autotransformers which step the voltage down to 69kV.

The FG&E transmission system originates at Flagg Pond with three 69kV lines. In total, the system consists of seven 69 kV lines which serve 10 distribution substations. These substations reduce the 69 kV voltage down to the distribution voltage of 13.8kV. There are no customers in the FG&E system served directly from the 69 kV system.

FG&E has a 13.8kV "feeder" system which serves an additional three 13.8 – 4kV distribution substations. In general, the 4 kV system serves approximately 15% of the entire system load.

3 Study Focus

This study is primarily focused on radial 4kV and 13.8kV distribution circuits and feeders as well as the loading on the substation transformers feeding them. System modifications are based upon general distribution planning criteria. A 69kV system study was completed in 2002[1] as part of MDTE 01-67. A system study is also being completed this year and is scheduled to be released at approximately the same time as this study.

A detailed study of the network system in downtown Fitchburg was completed in 2001[2]. As recommended in that study, several modifications have recently been made to the network system. An updated network system study is planned to be completed later this year.

Footnote 1 – Fitchburg Gas & Electric Company 2000 Electric Transmission Planning Study August 2002
Footnote 2 – Fitchburg Gas and Electric Light Co Underground Network Planning Study July 2001

4 Load Forecasts

A 6 year projection of summer and winter peak demands for each individual circuit and feeder was developed from historical monthly peak demand recordings. The projections include any known customer load removals and/or additions as well as any circuit reconfigurations and load transfers. For most of 1999, the monthly readings were not recorded. In these instances, it was assumed that the 1999 peak loads were the same as the 1998 peak loads for the same month.

A linear regression analysis was performed on the historical loads to forecast future peak demands. Where data is complete this approach works very well. However, where data is inconsistent or incomplete a linear 2.5% annual load increase was used starting with the most recent summer or winter peak demand. In general, one standard deviation was added to provide more conservative results. For those instances where the linear regression evaluation demonstrated a decreasing trend, the historical loads were more closely analyzed. In most cases, the load for that particular circuit or feeder was determined to remain the same or to increase using the linear growth evaluation. The following table shows the top ten circuits based upon the load projections. Summer and winter load forecasts are attached in Appendix A.

Ranking	Circuit	% Loading Increase 2004-2008
1	35H36 *	110.9% *
2	15W17	53.6%
3	30W31	48.8%
4	35H35	37.5%
5	21F41 *	31.2% *
6	31W37	30.9%
7	15W16	22.3%
8	20H22	18.8%
9	11W11	16.4%
10	8 circuits @	13.1%

* The load increase on circuits 35H36 and 21F41 include the addition of a large water treatment facility currently under construction along Rindge Road in Fitchburg.

5 Rating Analysis

A detailed review of the limiting factors associated with each circuit was completed. The limiting factors include CT (current transformer) ratings, protection device settings, switch ratings, circuit exit conductor size, and transformer ratings. Transformer and conductor ratings were obtained from the Unitil Transformer and Conductor Rating Manuals. The distribution system circuit limitations can be referenced in Appendix B.

The transformer and circuit loading used in this analysis is based upon the load forecasts described in Section 4 and listed in Appendix A. For conservatism, the phase with the heaviest loading (kVA) was translated to the other two phases. Transformer and circuit loading graphs are included in Appendix C & D respectively.

6 Analysis and Findings

This section details the findings resulting from the analysis described in Section 5 as well as an analysis of step-down transformer loading and a review of circuit load phase imbalance. Individual project descriptions and associated cost estimates intended to address each of the identified issues are included in Section 8.

6.1 Transformer Loading

An overload threshold of 90% was used in the analysis*. Those transformers where the projected load will reach or exceed 90% of their seasonal rating are listed here.

Townsend Substation Transformer:
This transformer will reach 90% of the summer rating in the summer of 2004. Load will need to be transferred prior to the summer of 2004 in order to alleviate a potential overload condition.

Pleasant Street 13.8kV Substation Transformer:
This transformer will reach 91% of the summer rating by the summer of 2006. Load will need to be transferred prior to the summer of 2006 in order to alleviate a potential overload condition.

Rindge Road Substation Transformer:
Steady load growth in this area and the addition of a water treatment facility on Rindge Road (circuit 35H36), currently scheduled to receive permanent service in February of 2004, will create an overload condition on the substation transformer. Preliminary load data analysis estimates the peak demand at this site to be approximately 500kVA. Based on the current projection analysis, this will result in a load reaching 92% of the transformer rating during the summer of 2006. In addition, circuit analysis shows that this load increase will immediately create low voltage problems on the circuit.

The customer is requesting a three phase service which will require a primary overhead line extension as the site is situated on Rindge Road where only two phases of primary exist. In order to meet the service requirements of this customer and avoid low voltage conditions for other FG&E customers, three phase primary will be extended to the site and most of the circuit will be converted to 13.8kV. Once the conversion is completed, the entire load on circuit 35H36 will be transferred onto circuit 21W36 essentially eliminating circuit 35H36. Therefore, all of the issues identified above will be addressed as part of the customer requirements for service.

6.2 Circuit Loading

An overload threshold of 90% was used in the analysis*. Those circuit elements where the projected load will meet or exceed 90% of their rating are listed here.

Circuit 20H24:
This circuit will reach the 90% of the circuit rating in summer of 2004. The limiting factor on this circuit is the multi-ratio current transformers which are used for metering purposes only. The CT's are currently set on the 300:5 tap. An EWR will be issued in 2004 to change the tap setting to a 400:5 ratio. No protection setting changes are required.

Circuit 39W18:
This circuit will reach the 92% of the circuit rating in summer of 2004. The limiting factor on this circuit is the multi-ratio current transformers which are used for protection and metering. The CT's are currently set on the 200:5 tap. An EWR will be issued in 2004 to change the tap setting to a 400:5 ratio along with revised protection settings.

* A threshold of 90% is used as an initial flag to allow for phase imbalance. Further investigation into the actual loading is used to determine the required timing for capital projects.

Circuit 50W55:
This circuit will reach 92% of the its rating in summer of 2007. The limiting factor on this circuit is the SM5 300E bypass fuses in the recloser bypass disconnect switch. The most cost effective solution to address the overload is to purchase 400A "solid" fuse links for the SM5 fuse holders. These links would be used to replace the existing 300E fuses during times of peak loading. An EWR would be issued in 2007 to purchase the solid fuse links assuming the projected load levels are reached. This problem could also be addressed through distribution switching as there is an existing distribution circuit tie between circuits 50W55 & 01W06. Circuit 50W55 can be transferred to 01W06 when the recloser needs to be bypassed for maintenance, etc.

6.3 Step Transformer Loading

The loading limit used in the step transformer analysis is 120% of the nameplate rating. This is based upon the "Normal Life Expectancy Curve" in ANSI/IEEE C57.91-latest edition. The ambient temperature assumed is 30^{O}C (86^{O}F). Step transformer meters are recorded quarterly and reviewed for potential overloads. Historical loading charts can be referenced in Appendix E.

Circuit 01W04 – Walnut Street:
Circuit analysis has identified the 250kVA transformer connected to phase B as potentially becoming overloaded to 141% of nameplate during the summer 2003. This circuit model also shows the transformers on phases A & C as being lightly loaded at 41% and 18% of nameplate respectively. However, thermal demand readings for May, 2003 indicate the actual loads on phases A-C to be 58%, 50%, and 94% of transformer nameplate respectively. Therefore, the accuracy of the circuit model is questionable. The circuit model problem is most likely due to improper phase allocation of connected customer transformer kVA. A field audit of this area would be required to correct the problem. However, actual thermal demand reads will be monitored throughout the summer and the condition will be re-evaluated. If confirmed, the overload condition can be addressed through load balancing.

Circuit 21W36 - Kinsman Road:
This step transformer is a single phase 167kVA unit which has been identified through circuit analysis as potentially becoming overloaded to 126% of nameplate during the summer of 2005. However, the May 2003 thermal demand readings indicate 96% loading at this time. The actual load on this transformer will be monitored going forward and if the projected level is reached, this transformer will need to be replaced with a 333kVA unit in 2005.

6.4 Phase Imbalance

Each circuit was reviewed for phase balancing. The per-phase loading was averaged over a timeframe of April 2002 through April 2003. All of the metering points (circuits and substation transformers) have been ranked based upon the worst phase imbalances.

In general, the goal for phase balancing is 10%. The following is a list of circuits where the imbalance is greater than 20% which is considered severe. An EWR will be issued in 2004 to reduce the phase imbalances listed below in order to meet the 10% criteria. The values listed below are absolute seasonal averages and do not consider non-coincident peak loading between phases.

Circuit	% Imbalance	Solution	% Imbalance After Load Swap (estimated)
01W04	55.2%	Swap 240 kVA from A to B Swap 160 kVA from A to C	11.2%
30W31	48.6%	Swap 120 kVA from A to B Swap 80 kVA from C to B	3.8%
05H12	45.5%	Swap 25 kVA from A to C Swap 25 kVA from B to C	1.5%
35H35	34.2%	Swap 40 kVA from C to A Swap 40 kVA from C to B	3.4%
25W27	29.2%	Swap 200 kVA from A to B Swap 200 kVA from A to C	10.0%
01W02	27.6%	Swap 160 kVA from A to C	9.6%
35H36	27.0%	Swap 60 kVA from C to B	6.5%
01W06	26.2%	Swap 200 kVA from A to B	6.2%
01W01	22.8%	Swap 160 kVA from A to B Swap 160 kVA from A to C	10.0%
05H06	21.7%	Swap 50 kVA from A to B Swap 50 kVA from A to C	5.6%

7 Circuit Analysis Results

Circuit analysis is completed for the FG&E system on a three year rotating cycle where each circuit is reviewed once every three years. Now that the FG&E distribution system has been completed in Genmap, the accuracy of the circuit models created will be significantly increased which will ultimately improve the process of identifying required capital improvement projects to address potential system deficiencies going forward.

Windmil circuit analysis is used as to identify potential problem areas. All identified problems should be followed up with verification from field measurements. Solutions to the deficiencies noted below are detailed in Section 8.

7.1 Circuit Analyzed

The following is a list of the circuits analyzed in 2002-03:

05H12
01W04
11W11
20H24
25W29
25W28
50W51
50W56

7.2 Voltage Concerns

Circuit analysis is set to identify areas where the voltage on the circuit goes outside of a pre-determined acceptable range. The acceptable range used for this analysis is 116-125 volts on a 120 volt base. The instances where voltage is predicted to be outside of this range are listed below.

Circuit 05H12 – Airport Road:
Circuit analysis has identified the voltage on phase B of this circuit running along Airport Road during the projected 2004 summer peak to be 113 volts. The voltage on the other two phases ranges between 116–119 volts. However, circuit analysis shows that the voltage problem can not be alleviated through the load balancing indicated in section 6.4 alone. The low voltage will be corrected for the remainder of the study period by transferring the load on circuit 05H12 to circuit 40W39. This will be accomplished by installing a bank of (3) 333kVA stepdown transformers on Airport Road near the intersection of Airport and Bemis Roads. Circuit 05H12 will remain in service and energized up to the circuit getaway riser pole on Intervale Road and used as a backup for the new 4kV section of 40W39 along Airport Road. This project will correct the voltage problem and reduce the system's reliability exposure due to faults on the underground cable serving the South Fitchburg S/S.

A cable fault recently occurred (June 03) which took in excess of 18 hours to repair. While repairs were being made, the South Fitchburg load was picked up by Pleasant Street S/S through a circuit tie with 31H34. During the peak load period, voltages were measured as low as 99volts at the ends of Summer Street and Airport Road resulting in several low voltage complaints which affected customer operations. These readings were recorded after the 13.8kV bus voltage at Pleasant Street S/S was raised as much as possible. As a result, a short outage was necessary to change the mobile transformer tap setting. This outage affected all the customers on 31H34, 05H06 & 05H12. The low voltage experienced may not have occurred and certainly would not have been as severe if the 05H12 load was removed from South Fitchburg S/S.

8 Detailed Recommendations

8.1 Townsend S/S Transformer: Load Relief – (2004)

As detailed in the transformer loading section of this report, the Townsend substation transformer will reach 90% of the summer normal rating (12.5 MVA) in 2004. In 2003, a portion of circuit 15W17 was transferred to circuit 39W18 (West Townsend S/S). As part of this project, a new loadbreak switch will be installed on 15W17 (Main Street) up-line of the new open point between 15W17 & 39W18. The switch will enable an additional ±1 MVA of load to be transferred on to circuit 39W18 simply through switching and will become the new normally open tie point between the two circuits. This project will reduce the projected loading on the station transformer to approximately 10.2 MVA or 82% of the summer rating.

Estimated Project Cost: $3,000

8.2 Rindge Road S/S Transformer: Load Relief – (2004)

Without circuit modifications, the Rindge Road substation transformer will exceed 92% of its summer rating in 2006 and voltages as low as 112 volts will be experienced on circuit 35H36 as soon as the proposed Rindge Road water treatment plant comes online in February, 2004. In addition, this plant requires a three phase service and is situated along Rindge Road where only 2 phases of primary exist. In order to serve this proposed load addition, three phase primary will need to be extended approximately 2 overhead sections and the primary voltage will be converted to 13.8kV from the substation up to the intersection of Rindge and Bennett Roads. This conversion will include replacing several polemount transformers of various sizes and one three phase 75kVA padmount transformer currently serving a pump house in the Stoneybrook URD. According to plant records, the remaining padmount transformers in this URD are dual voltage and will not require replacement. A new 167kVA polemount 7.97:2.4kV stepdown transformer will be installed at the intersection of Rindge and Bennett Roads to provide single phase 2.4kV service to the portions of the circuit beyond this point. Once the conversion is complete, the entire circuit will be transferred to circuit 21W36. This project will increase the voltages at the end of the line to 117volts and the new projected loading on the Rindge Road transformer will be approximately 1MVA or 55% of the summer rating.

Estimated Project Cost: $45,178

8.3 Circuit 20H24: Change CT Ratio – (2004)

The current transformers for circuit 20H24 will reach 90% of the existing tap setting rating during the summer of 2004. An EWR will be issued in 2004 to change the tap setting from 300:5 to a 400:5 ratio. No protection setting changes are required.

Estimated Project Cost: $1,000

8.4 Circuit 39W18: Change CT Ratio – (2004)

The current transformers for circuit 39W18 will reach 92% of the existing tap setting rating in the summer of 2004. An EWR will be issued in 2004 to change the tap setting from 200:5 to a 400:5 ratio. Protection setting changes will also be required as part of this project.

Estimated Project Cost: $2,000

8.5 Circuit 01W04: Walnut St Load Balance – (2004)

The May 2003 thermal demand readings indicate an existing load of 94% of nameplate on the phase C step transformer. Phases A & B are loaded to 58% and 50% of nameplate respectively. An EWR will be issued in 2004 to remove approximately 70kVA of load from phase C. 45kVA will be transferred on to phase B and 25kVA will be assumed by A. This should balance the load on the entire stepdown bank to within 65-70% of nameplate.

Estimated Project Cost: $1,000

8.6 Circuit 05H12 Load Transfer – (2004)

Circuit analysis has identified the phase B voltage at the end of Airport Road to be 113 volts during the projected 2004 summer peak. The project to relieve this condition involves transferring all of the load from circuit 05H12 to circuit 40W39. Circuit 05H12 will remain in service to serve as the backup source to the 4kV portion of 40W39 along Airport Road. This will be accomplished by installing a new bank of (3)-333kVA 7.97:2.4kV stepdown transformers on Airport Road near the intersection of Airport and Bemis Roads. The direct buried underground circuit getaway cable for circuit 05H12 will remain energized up to the riser pole located on Intervale Road next to the railroad bed. There is an existing set of solid blades which will become the normally open point between 05H12 and the new 4kV section of 40W39 serving Interval, Mack, Bemis and Airport Roads. This project will increase the voltage at the end of Airport Road to 116 volts for the remainder of the study period and relieve approximately ½ MVA of load from the South Fitchburg transformer. This new 2004 projected peak load on the South Fitchburg transformer will be 1.1MVA or 30% of the summer rating. This project aligns with the distribution system master plan outlined in section 9 included in this report.

Estimated Project Cost: $15,947

8.7 Circuit Load Balancing – (2004)

An EWR will be issued outlining the load swaps to be performed on the 10 circuits identified in Section 6.4. Loads will be transferred between phases as outlined in the table shown in this section.

Estimated Project Cost: $2,400

8.8 Circuit 01W04: Re-conductor Phase 2 – (2004)

Circuit 3-4 originally was two circuits 3 and 4 which originated from the Beech Street substation and tied to feeders 3 and 4 out of Summer Street. In the past, circuit 3 (2/0 Cu) and circuit 4 (3/0 AL) were paralleled together to alleviate loading concerns which created a single distribution circuit emanating from the Beech Street S/S currently designated as 01W04. In 2002, a project was issued to re-conductor the mainline portion of this circuit from the Beech Street S/S to South Street with 336.4 spacer cable. This represents approximately ½ of the mainline to the Summer Street S/S. The remainder of the mainline heading toward the Summer Street S/S is the old double circuit construction and does not meet current construction standards. Recent projects have also shown that many of the crossarms are rotten and pole tops are split.

An additional benefit to the completion of this project will be the ability to tie between distribution circuits out of Beech Street & Summer Street substations. As an example, on June 23rd of this year a squirrel contact caused insulator damage on the 13.8kV bus at Summer Street resulting in a 76 minute outage. If the tie to Beech Street had been available, the section of bus feeding 40W39 could have been isolated and picked up with 01W04. This would have restored power to 40W39 (including PGM), all of South Fitchburg (05H6 & 05H12). Simonds Saw (40W38) could have also been restored via a circuit tie between circuits 40W38 & 40W39. The system reliability impact of this outage on the circuits noted above affected the 497 customers, including some key accounts, and amounted to 37,772 customer-minutes. These minutes would have been significantly reduced if switching was available. This tie will also provide back up to circuit 01W04 via the Summer Street bus and, in some instances, may be used to back up 01W02 & 01W06. In most cases, this tie would not be able to back up 01W01 due to the loading on this circuit.

This project will be the second phase of a two phase project and would consist of re-conductoring ~6,000 feet of double circuit overhead line from the intersection of South Street and Electric Avenue to the Summer Street Substation. New 336.4 AA spacer cable with a 0000127 AWA (4/0) messenger will be installed along this route and the existing double circuit conductor and appurtenances will be removed. This project includes a river crossing where conductor had fallen during a storm and was not repaired.

Estimated Project Cost: $201,332

8.9 Circuit 21W36: Replace Kinsman Rd Step – (2005)

The 167kVA step transformer installed at this location is currently loaded to 160kVA. Circuit analysis is projecting load growth in this area to cause an overload condition on this transformer of 126% of nameplate during the summer of 2005. The actual thermal demand readings will be monitored to confirm the projections are accurate. If the projected load is reached, a 333kVA, 7.97/2.4kV transformer will be installed to replace the existing unit in 2005.

Estimated Project Cost: $5,500

8.10 Pleasant Street Transformer; Load Relief – (2006)

The current load forecast is projecting that the load on the Pleasant Street 13.8kV transformer will reach 14,558MVA or 91% of its summer rating in 2006. The ultimate goal of this project will be to remove approximately 2½ MVA of load from the Pleasant Street transformer. This will be accomplished by performing two separate load transfers. The first load transfer will remove ±1MVA from circuit 31W38 and the second will relieve ±2 MVA from circuit 31W37. The project to transfer load from 31W38, outlined below, will be performed in 2006. This will reduce the load on the transformer to 85% of its rating and alleviate the immediate overload concerns. The load will again reach the 90% threshold sometime during the 2007-8 timeframe. At this time, the second load transfer project on circuit 31W37 will be required. At the completion of the second project, the projected load on the station transformer will be ~13MVA or 81% of the summer rating.

The first project to be performed will transfer approximately 1MVA of load from 31W38 to 30W31. This will be accomplished by closing the normally open tie between the two circuits located on Massachusetts Ave in Lunenburg. A new 3-pole, gang operated loadbreak switch will be installed as the new normally open point between the two circuits. The exact location of this switch will be determined following closer analysis.

The second load transfer project will be completed during the 2007-8 time period. The project required to transfer ~2MVA of load off of circuit 31W37 will be substantially more difficult than the project described for 31W38. Although there is an existing tie with 40W40 located on Chapel Street, this tie is located just outside the substation and is used as a backup source for the entire circuit. One solution to relieve load is to build a line extension along the John Fitch Highway from the intersection of Rte 2A down to circuit 40W40. Load would then be transferred and a new open point created via a new 3-phase, gang operated loadbreak switch.

A second possible solution would be more costly but would provide significant benefits to system reliability and operating conditions elsewhere on the system. This project would involve a new circuit position at the West Townsend S/S and the construction of a new overhead circuit along Rte 119 toward Ashby. The new circuit would be spacer cable construction and overbuilt above circuit 39W19. The proposed circuit path will follow the mainline of circuit 39W19 along Rte 119, into Ashby and end at the intersection of Greenville Road. The entire portion of 39W19 heading south down Greenville Road toward Fitchburg will be transferred onto the new circuit. This project will also require a significant 3 phase extension down Wares Road and Pearl Hill Road in order to meet with the 3 phase primary of circuit 31W37. A new 3-phase, gang operated loadbreak switch will be installed in order to create a normally open tie between the new circuit and circuit 31W37. Three phase primary can also be extended from the new circuit down Fitchburg State Highway as a future back up source to circuit 21W36. This solution will relieve the loading concerns at Pleasant Street and improve reliability by creating additional circuit ties and reducing the customer count on circuit 39W19. Completion of this project would also improve the voltage conditions throughout Ashby.

Estimated Project Cost: $TBD

8.11 Circuit 50W55: Bypass Fuse Modification – (2007)

The limiting factor on this circuit is the SM5 300E bypass fuses which are projected to reach 92% of their rating in the summer of 2007. An EWR will be issued in 2007 to purchase 400 amp solid fuse links for the SM5 fuse holders. These units will be used to replace the existing 300E fuses as needed during times of peak loading. This problem can also be addressed through the distribution switching described in section 6.2.

Estimated Project Cost: $3,000

9 Master Plan

The majority of the FG&E service territory is served via 13.8Y/7.97kV overhead distribution. There are several areas of 4.16Y/2.4kV distribution as well. Many of the 13.8kV circuits have distribution ties with adjacent circuits. However, there are several areas, especially around the perimeter of the territory, where additional ties would benefit system reliability. Circuit ties on the 4kV distribution system are limited. A map of the entire system overview showing the circuit mainline paths and the existing circuit ties is included in Appendix F. This map also identifies potential locations for additional tie switches. Some sections of mainline would need to be extended and/or reconductored with 336.4 AA in order to accommodate these proposed circuit ties. Going forward, this map should be used as a guide for constructing system expansions in order to facilitate the implementation of this master plan. This map may also be a useful operational tool during restoration efforts.

The remainder of this section identifies issues which are of specific concern regarding the system's safe and reliable operation. Recommendations for system modifications will be provided, aimed at improving operational safety or aiding restoration efforts. These issues will become the focal points of future studies as this master plan evolves.

<u>Ashby & North Fitchburg</u>
The load growth in the area of the Pleasant Street S/S has increased to a point where circuit reconfigurations are required to prevent a potential overload condition of the Pleasant Street 13.8kV transformer. In addition, the load growth in the Rindge Road area has driven the rapid expansion of circuit 21W36. One of the options identified to relieve the Pleasant Street loading is to create a third 13.8kV circuit out of West Townsend S/S. This new circuit would provide load relief and potentially create many other operational benefits which will inevitably improve overall system reliability. The new circuit will reduce the exposure on circuit 39W19 by reducing its customer count. It could be utilized as a backup source for circuits 31W37, 39W19, and 21W36 which will include all of 35H36 following the conversion & transfer project scheduled for 2004. The new circuit will also improve voltage levels in the town of Ashby by reducing the load on circuit 39W19.

<u>Summer Street Reconfiguration</u>
Summer Street substation has two 69kV bus sections separated with a bus tie breaker. The 06 line originates from Bus 1 and serves Sawyer Passway substation. The transformer breaker is also served from Bus 1. This transformer serves the 13.8kV load at Summer Street and serves the 1303 and 1309 lines which provide backup for Sawyer Passway. Since the 06 Line and the Summer Street transformer are tapped from Bus 1, a single bus fault will create an outage for Summer Street (which includes South Fitchburg) and Sawyer Passway (which includes Nockege). Approximately 4,680 customers would be affected by this outage (18% of the entire system). An outage like this has occurred in the past 10 years. Relocating the 06 line breaker to the end position on Bus 2 will correct this issue. This project would include new 69kV disconnect and bypass switches, structure modifications, foundation, overhead line relocation and control wiring.

<u>PILC Replacement</u>
The underground system in the Main Street area of the FG&E system consists of cables of varying vintages. The types of cable consist of PILC (Paper Insulated Lead Cable), varnished cambric, and unshielded rubber insulated cable. These are a combination of 13.8kV and 4kV cables. Some of this cable date back to the 1920's. None of the cable has been tested, so the actual condition of the cable is unknown. There has been some recent concern that some of the neutrals and neutral bus in the manholes are bare copper. The result is a galvanic reaction between the lead sheath of the PILC cable and the copper connections. The result is thinning and pitting of the lead sheath. An effort to coat all bare copper in the manholes with a silicone paint to stop the galvanic action has been completed. Over the next few years, a plan should be developed to identify and address the aging cable. The plan should include research into kinds

and amounts of cable, recommended testing and a multi-year replacement plan.

Backup for 22W3

Circuit 22W3 is served from Sawyer Passway substation. The circuit exits the substation overhead, hits a riser and goes underground to the river, rises up over the river and then goes back underground to serve the customers on 22W3. There are only 12 customers on this circuit, but there is no way to backup these customers in the event of a cable fault. The customers on this circuit include a grocery store, restaurants, and various store fronts. A cable failure could result in an extended outage. A project should be considered to add cable from Main Street across the Water Street bridge and up to the strip mall area.

Pleasant Street and Canton Street 4 kV

The 4 kV circuits out of Pleasant Street and Canton Street do not have the ability to tie to adjacent circuits. In the not too distant future, the 4 kV load is going to reach the rating of the 3.75 MVA mobile. At that time, the most cost effective solution is to convert the 4 kV circuits out of Canton Street to 13.8 kV and relocate the Canton Street 4 kV transformer to the Pleasant Street substation. The Pleasant Street and Canton Street 4 kV transformers are identical units. The addition of a second transformer at Pleasant Street would provide backup in the event of a transformer failure.

South Fitchburg Area

The substation is served via direct buried cables adjacent to the railroad bed. This cable is lead-shielded type installed in 1956. The exact condition of the cables is not known. However, faults have been experienced on this cable as recently as June of this year and in October of last year. There is one existing tie with Pleasant Street (31H34) to backup the two 4kV circuits (05H06 and 05H12) out of South Fitchburg. The most recent fault resulted in severe low voltage conditions (99volts) on both South Fitchburg circuits when load was picked up out of Pleasant Street while repairs were made. The fault of October, 2002 resulted in extended outages to 40W39, 05H06 and 05H12 which totaled 42,918 customer minutes of interruption. In order to gain some insight of the actual condition of this cable, samples will be sent to Hendrix for analysis later this year.

A new back up source for the South Fitchburg S/S could be constructed with circuit 40W40 as part of a road widening project currently planned by the Massachusetts Highway Department. The proposed project scope involves widening a portion of Summer Street which will require several pole relocations. Circuit 40W40, which currently dead ends at the intersection of Bemis Road and Summer Street, could be overbuilt down to the corner of Summer Street and Poplar Street as part of this project and be available as back for the South Fitchburg S/S. However, based upon the age and condition of the equipment installed at the South Fitchburg substation, the ultimate long term plan is to install step transformers on circuit 40W40 to serve the load on circuit 05H06 similar to the project proposed for 2004 where all of circuit 05H12 will be transferred onto circuit 40W39. The South Fitchburg S/S will be eliminated once the load is removed from both of these circuits.

Nockege Substation

Nockege substation is a 13.8 - 4kV substation with a 5 MVA transformer. In the event of a transformer failure or bus fault, the only way to serve the load is to install the mobile transformer. The mobile is rated at 3.75 MVA. Load projections show that in 2006 the 4kV load will reach this level. The two 4kV circuits at Nockege (20H22 and 20H24) serve approximately 1300 customers. The 13.8kV bus at Nockege has spare bays available to create a new distribution circuit. A future project should be considered to convert approximately 1.5 miles of 4kV and combine the circuits into one 13.8kV circuit. Approximately three stepdown transformer locations will be required. A new 13.8kV breaker position and regulators will also be required. At that time, the old 4kV equipment can be eliminated from this substation. This issue should be reviewed more closely as the 4kV load approaches the 3.75 MVA limit.

Circuit 20H24: Eliminate Unshielded Cable

The cable in question is an unshielded rubber insulated cable installed in the 1950's. This cable has experienced extended outages in the past because fault locating equipment does not work well on unshielded cable. The last extended outage occurred on January 9, 2002, and lasted for almost 7 hours. In 2000, a 15 hour outage occurred on this circuit. If this cable is not replaced, it is highly probably that future faults will take just as long to locate and repair. In addition, the cable joints have begun to degrade and absorb moisture. This is evident by the audible noise when a manhole is entered. This cable poses a real reliability concern for the customers in the downtown Fitchburg area. Based upon recent history, the potential for additional failures is high. A multi-year project was started in 2003 to replace this cable and should be continued going forward.

10 Conclusion

The FG&E distribution system has made great strides in the past several years. The addition of Princeton Road, Sawyer Passway and voltage regulation at Summer Street has provided stability to the system. Looking forward, load growth in the Rindge Road and Pleasant Street areas will be of primary focus as well as the development of the overall system master plan. Continued circuit analysis will help identify problems and areas of concern which have gone unnoticed in the past. The models created for circuit analysis will become an invaluable tool to assist in identifying the best solutions to the challenges faced with improving the overall system performance and reliability. Whenever possible, system upgrades will use the guidelines set forth within the master plan presented in section 9 on this report. It is recognized that this study is a living document and it will be continually updated as the system's needs change.

Appendix A

Summer and Winter Load Forecasts

	Summer Peak Loads (three-phase kVA)					
		Projected				
Distribution Element	2003	2004	2005	2006	2007	2008
Beech St.#1 Xfmr	13,525	13,857	14,197	14,546	14,904	15,270
01W01	7,384	7,569	7,758	7,952	8,151	8,354
01W02	2,773	2,842	2,913	2,986	3,061	3,137
01W04	3,123	3,201	3,281	3,363	3,447	3,533
01W06	245	245	245	245	245	245
Canton St. 13.8 kV #1 Xfmr	6,180	6,383	6,586	6,789	6,992	7,195
11W11	6,180	6,383	6,586	6,789	6,992	7,195
Canton St. 4.16 kV #2 Xfmr	2,682	2,682	2,682	2,682	2,682	2,682
11H10	1,105	1,105	1,105	1,105	1,105	1,105
11H11	1,657	1,657	1,657	1,657	1,657	1,657
Lunenburg 13.8 kV Xfmr	8,065	8,409	8,753	9,098	9,442	9,786
30W30	5,912	6,046	6,179	6,313	6,447	6,581
30W31	2,153	2,364	2,574	2,784	2,995	3,205
Nockege 4.16 kV Xfmr	3,467	3,573	3,680	3,789	3,898	4,009
20H22	1,536	1,594	1,651	1,709	1,767	1,824
20H23	0	0	0	0	0	0
20H24	1,931	1,979	2,029	2,079	2,131	2,185
Pleasant St. 4.16 kV Xfmr	2,162	2,216	2,271	2,328	2,386	2,386
31H34	2,162	2,216	2,271	2,328	2,386	2,386
Pleasant St. 13.8 kV Xfmr	13,128	13,605	14,081	14,558	15,035	15,511
31W37	7,829	8,313	8,797	9,282	9,766	10,251
31W38	7,972	8,061	8,150	8,239	8,328	8,417
Princeton Rd #1 Xfmr	0	0	0	0	0	0
50W55	5,561	5,700	5,843	5,989	6,138	6,138
50W56	5,553	5,692	5,834	5,980	6,129	6,283
Princeton Rd #2 Xfmr	12,636	12,952	13,276	13,608	13,948	14,101
Princeton Rd #3 Xfmr	9,784	9,784	9,784	9,784	9,784	9,784
50W51	1,522	1,560	1,599	1,639	1,680	1,680
50W53	7,131	7,309	7,492	7,679	7,871	7,871
50W54	3,442	3,528	3,616	3,707	3,799	3,799
Rindge Rd 4.16 kV Xfmr	1,099	1,522	1,594	1,666	1,738	1,811
35H35	896	963	1,030	1,098	1,165	1,232
35H36	528	1,009	1,034	1,060	1,087	1,114
River St. 13.8 kV Xfmr	10,802	11,072	11,349	11,632	11,923	11,923
25W29	5,498	5,635	5,776	5,920	6,068	6,068
25W27	2,358	2,417	2,478	2,540	2,603	2,603
25W28	3,570	3,659	3,751	3,844	3,941	3,941
Sawyer Passway 13.8 kV Xfmr T1	8,690	10,668	10,822	10,979	11,142	11,141
22W17	700	700	700	700	701	700
22W2	829	850	871	893	915	915
1303	3,984	7,641	7,641	7,641	7,642	7,641
22W1	4,500	4,612	4,728	4,846	4,967	4,967
22W3	669	686	703	720	738	738
Sawyer Passway 13.8 kV Xfmr T2	9,487	9,724	9,967	10,216	10,471	10,471
22WFUT	0	0	0	0	0	0

	Summer Peak Loads (three-phase kVA)					
		Projected				
Distribution Element	2003	2004	2005	2006	2007	2008
22W8	837	858	879	901	924	924
1309	7,641	7,641	7,641	7,641	7,641	7,641
22W10	3,984	4,084	4,186	4,290	4,398	4,508
22W11	845	866	888	910	933	933
S. Fitchburg 4.16 kV Xfmr	1,639	1,678	1,717	1,757	1,797	1,837
5H06	1,091	1,116	1,142	1,167	1,192	1,217
5H12	548	562	576	590	605	620
Summer St. 13.8 kV B123 Xfmr	17,480	20,678	20,761	23,303	20,622	20,707
1303	3,984	7,641	7,641	7,641	7,642	7,641
1309	7,641	7,641	7,641	7,641	7,641	7,641
40W38	2,598	2,663	2,730	2,798	2,868	2,939
40W39	5,498	5,498	5,498	5,498	5,498	5,498
40W40	3,016	3,056	3,096	3,136	3,176	3,216
Townsend 13.8 kV Xfmr	10,783	11,239	11,695	12,151	12,607	13,063
15W15	5,450	5,569	5,687	5,805	5,923	6,042
15W16	5,387	5,627	5,867	6,106	6,346	6,586
15W17	1,547	1,713	1,879	2,045	2,210	2,376
15W17A	0	0	0	0	0	0
Wallace Rd 13.8 kV	0	0	0	0	0	0
21F41	3,136	3,610	3,734	3,859	3,986	4,115
21W36	2,037	2,088	2,140	2,193	2,248	2,304
W. Townsend 13.8 kV Xfmr	6,552	6,663	6,775	6,886	6,998	7,109
39W18	4,299	4,353	4,407	4,462	4,516	4,570
39W19	2,252	2,310	2,367	2,425	2,482	2,539

Fitchburg Gas and Electric
5-Year Load Forecast
2004-2008

Distribution Element	Winter Peak Loads (three-phase kVA)					
	Projected					
	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
Beech St.#1 Xfmr	11,061	11,472	11,884	12,296	12,707	13,119
01W01	4,732	4,751	4,770	4,789	4,808	4,827
01W02	3,048	3,258	3,469	3,679	3,890	4,100
01W04	3,036	3,218	3,400	3,582	3,764	3,946
01W06	245	245	245	245	245	245
Canton St. 13.8 kV #1 Xfmr	5,186	5,316	5,448	5,585	5,724	5,867
11W11	5,186	5,316	5,448	5,585	5,724	5,867
Canton St. 4.16 kV #2 Xfmr	1,991	1,991	1,991	1,991	1,991	1,991
11H10	1,273	1,273	1,273	1,273	1,273	1,273
11H11	865	865	865	865	865	865
Lunenburg 13.8 kV Xfmr	6,537	6,579	6,620	6,661	6,703	6,744
30W30	5,327	5,359	5,391	5,423	5,455	5,487
30W31	1,210	1,220	1,229	1,239	1,248	1,258
Nockege 4.16 kV Xfmr	3,247	3,302	3,358	3,413	3,469	3,525
20H22	1,561	1,616	1,672	1,727	1,783	1,839
20H23	0	0	0	0	0	0
20H24	1,686	1,686	1,686	1,686	1,686	1,686
Pleasant St. 4.16 kV Xfmr	2,176	2,217	2,259	2,301	2,343	2,385
31H34	2,176	2,217	2,259	2,301	2,343	2,385
Pleasant St. 13.8 kV Xfmr	11,736	12,036	12,337	12,637	12,937	13,238
31W37	6,982	7,269	7,555	7,841	8,127	8,413
31W38	6,942	7,012	7,082	7,152	7,222	7,292
Princeton Rd #1 Xfmr	0	0	0	0	0	0
50W55	6,110	6,223	6,336	6,449	6,562	6,676
50W56	5,500	5,500	5,500	5,500	5,500	5,500
Princeton Rd #2 Xfmr	11,710	11,826	11,941	12,057	12,173	12,289
Princeton Rd #3 Xfmr	8,948	8,948	8,948	8,948	8,948	8,948
50W51	100	103	105	108	110	113
50W53	3,809	3,809	3,809	3,809	3,809	3,809
50W54	6,350	6,350	6,350	6,350	6,350	6,350
Rindge Rd 4.16 kV Xfmr	1,473	1,510	1,548	1,587	1,626	1,667
35H35	692	709	727	745	764	783
35H36	980	1,005	1,030	1,056	1,082	1,109
River St. 13.8 kV Xfmr	10,143	10,259	10,377	10,498	10,622	10,750
25W29	5,386	5,386	5,386	5,386	5,386	5,386
25W27	2,103	2,103	2,103	2,103	2,103	2,103
25W28	6,247	6,403	6,563	6,727	6,896	7,068
Sawyer Passway 13.8 kV Xfmr T1	11,715	11,990	12,272	12,562	12,858	13,162
22W17	700	700	700	700	700	700
22W2	2,505	2,568	2,632	2,698	2,765	2,834
1303	8,047	8,249	8,455	8,666	8,883	9,105
22W1	4,016	4,116	4,219	4,324	4,433	4,543
22W3	470	482	494	506	519	532
Sawyer Passway 13.8 kV Xfmr T2	8,103	8,306	8,513	8,726	8,944	9,168
22WFUT	0	0	0	0	0	0

Fitchburg Gas and Electric
5-Year Load Forecast
2004-2008

	Winter Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
22W8	861	882	904	927	950	974
1309	8,047	8,249	8,455	8,666	8,883	9,105
22W10	2,645	2,711	2,779	2,849	2,920	2,993
22W11	574	588	603	618	633	649
S. Fitchburg 4.16 kV Xfmr	1,211	1,242	1,273	1,304	1,337	1,370
5H06	798	818	838	859	880	902
5H12	453	464	476	488	500	513
Summer St. 13.8 kV B123 Xfmr	20,732	21,227	21,731	22,244	22,767	23,299
1303	8,047	8,249	8,455	8,666	8,883	9,105
1309	8,047	8,249	8,455	8,666	8,883	9,105
40W38	2,824	2,990	3,156	3,322	3,488	3,654
40W39	4,860	4,860	4,860	4,860	4,860	4,860
40W40	2,311	2,311	2,311	2,311	2,311	2,311
Townsend 13.8 kV Xfmr	10,619	10,983	11,346	11,709	12,072	12,436
15W15	4,854	4,871	4,888	4,905	4,922	4,940
15W16	4,129	4,179	4,229	4,280	4,330	4,380
15W17	1,726	1,777	1,828	1,879	1,930	1,981
15W17A	0	0	0	0	0	0
Wallace Rd 13.8 kV	0	0	0	0	0	0
21F41	2,759	2,828	2,899	2,971	3,045	3,121
21W36	1,286	1,318	1,351	1,384	1,419	1,454
W. Townsend 13.8 kV Xfmr	4,127	4,230	4,336	4,445	4,556	4,670
39W18	1,753	1,797	1,842	1,888	1,935	1,983
39W19	2,374	2,434	2,495	2,557	2,621	2,686

Appendix B

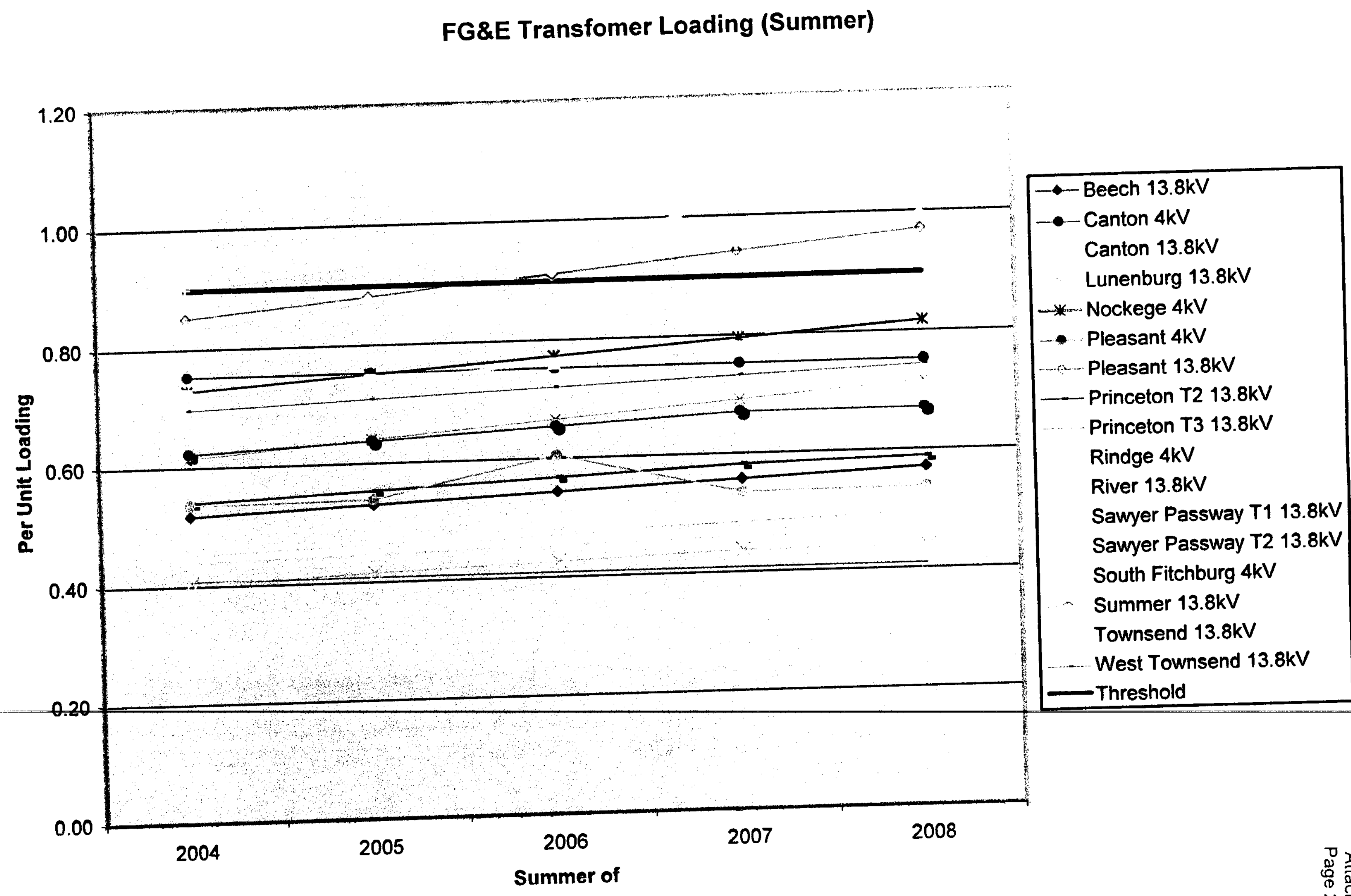
Distribution Circuit Limitations

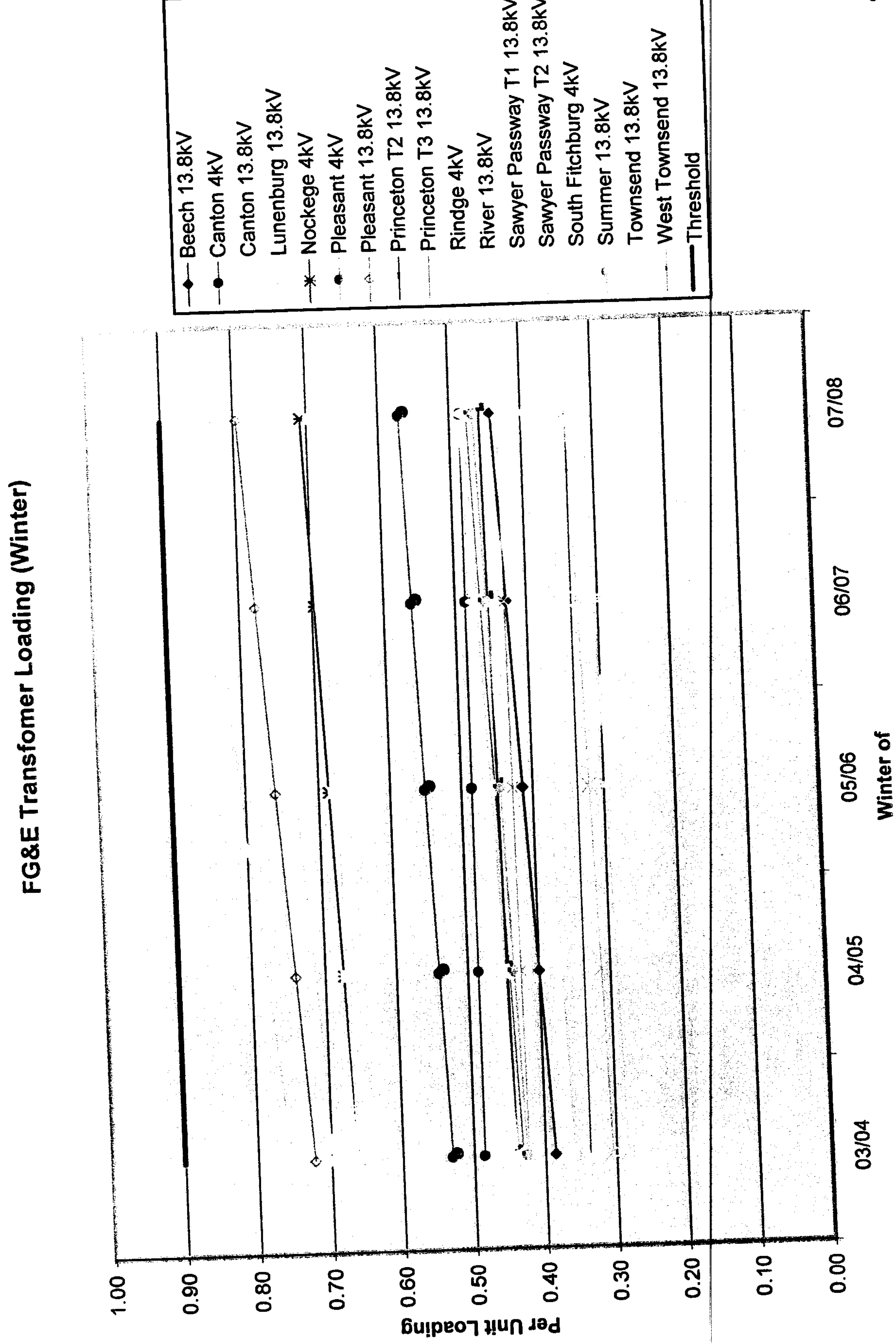
Distribution Element	System Voltage (kV)	Breaker Reclose	er (kVA) Winter	Overall Thermal Rating (Amps) Summer	(Amps) Winter	(kVA) Summer	(kVA) Winter	Limiting Element Summer	Limiting Element Winter
Beech St.#1 Xfmr	13.8	1200	30,120	1,117	1,200	26,700	28,683	Xfmr	Brkr/Rclsr
01W01	13.8	560		400	400	9,561	9,561	CT	CT
01W02	13.8	560		373	400	8,916	9,561	Wire	CT
01W04	13.8	560		400	400	9,561	9,561	CT	CT
01W06	13.8	560		373	400	8,916	9,561	Wire	CT
Canton St. 13.8 kV #1 Xfmr	13.8		19,710	730	825	17,460	19,710	Xfmr	Xfmr
11W11	13.8	560		531	560	12,692	13,385	Wire	Brkr/Rclsr
Canton St. 4.16 kV #2 Xfmr	4.16		4,110	494	570	3,560	4,110	Xfmr	Xfmr
11H10	4.16	280		280	280	2,017	2,017	Brkr/Rclsr	Brkr/Rclsr
11H11	4.16	280		280	280	2,017	2,017	Brkr/Rclsr	Brkr/Rclsr
Lunenburg 13.8 kV Xfmr	13.8		15,420	525	525	12,549	12,549	Reg	Reg
30W30	13.8	560		480	480	11,473	11,473	Trip	Trip
30W31	13.8	560		400	400	9,561	9,561	Trip	Trip
Nockege 4.16 kV Xfmr	4.16		5,000	680	680	4,900	4,900	Wire	Wire
20H22	4.16	400		300	300	2,162	2,162	CT	CT
20H23	4.16	400		300	300	2,162	2,162	CT	CT
20H24	4.16	400		300	300	2,162	2,162	CT	CT
Pleasant St. 4.16 kV Xfmr	4.16		4,110	494	570	3,560	4,110	Xfmr	Xfmr
31H34	4.16	560		531	560	3,826	4,035	Wire	Trip
Pleasant St. 13.8 kV Xfmr	13.8		18,050	669	680	15,980	16,254	Xfmr	Wire
31W37	13.8	560		531	560	12,692	13,385	Wire	Trip
31W38	13.8	560		500	500	11,951	11,951	CT	CT
Princeton Rd #1 Xfmr	13.8			600	600	14,341	14,341	Sw/Fuse	Sw/Fuse
50W55	13.8	1120		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
50W56	13.8	1120		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
Princeton Rd #2 Xfmr	13.8		26,550	1,003	1,111	23,980	26,550	Xfmr	Xfmr
Princeton Rd #3 Xfmr	13.8		26,530	1,003	1,110	23,970	26,530	Xfmr	Xfmr
50W51	13.8	1120		672	672	16,062	16,062	Trip	Trip
50W53	13.8	1120		768	768	18,357	18,357	Trip	Trip
50W54	13.8	1120		840	840	20,078	20,078	Trip	Trip
Rindge Rd 4.16 kV Xfmr	4.16		2,110	253	293	1,820	2,110	Xfmr	Xfmr
35H35	4.16	1200		320	320	2,306	2,306	Trip	Trip
35H36	4.16	1200		320	320	2,306	2,306	Trip	Trip
River St. 13.8 kV Xfmr	13.8		19,710	730	825	17,460	19,710	Xfmr	Xfmr
25W29	13.8	600		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
25W27	13.8	560		525	525	12,549	12,549	Wire	Wire
25W28	13.8	560		525	525	12,549	12,549	Wire	Wire
Sawyer Passway 13.8 kV Xfmr T1	13.8	1200	26,550	1,003	1,111	23,980	26,550	Xfmr	Xfmr
22W17	13.8	1200		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
22W2	13.8	1200		204	204	4,876	4,876	Trip	Trip
1303	13.8	1200		730	840	17,449	20,078	Wire	Trip
22W1	13.8	1200		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
22W3	13.8	1200		240	240	5,737	5,737	Trip	Trip
Sawyer Passway 13.8 kV Xfmr T2	13.8	1200	26,550	1,003	1,111	23,980	26,550	Xfmr	Xfmr
22WFUT	13.8	1200		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
22W8	13.8	1200		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
1309	13.8	1200		730	840	17,449	20,078	Wire	Trip
22W10	13.8	1200		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
22W11	13.8	1200		300	300	7,171	7,171	Byp.Fuse	Byp.Fuse
S. Fitchburg 4.16 kV Xfmr	4.16		3,700	514	514	3,700	3,700	Xfmr	Xfmr
5H06	4.16	255		200	200	1,441	1,441	CT	CT
5H12	4.16	255		200	200	1,441	1,441	CT	CT
Summer St. 13.8 kV B123 Xfmr	13.8	2000	48,270	1,600	1,600	38,244	38,244	Trip	Trip
1303	13.8	1200		531	694	12,692	16,588	Wire	Wire
1309	13.8	1200		663	868	15,847	20,747	Wire	Wire
40W38	13.8	600		400	400	9,561	9,561	CT	CT
40W39	13.8	600		400	400	9,561	9,561	CT	CT
40W40	13.8	600		400	400	9,561	9,561	Trip	Trip
Townsend 13.8 kV Xfmr	13.8		14,050	521	588	12,460	14,050	Xfmr	Xfmr
15W15	13.8	400		400	400	9,561	9,561	Brkr/Rclsr	Brkr/Rclsr
15W16	13.8	560		400	400	9,561	9,561	Trip	Trip
15W17	13.8	560		200	200	4,780	4,780	CT	CT
15W17A	13.8								
Wallace Rd 13.8 kV	4.16								
21F41	13.8	560		247	322	5,904	7,697	Wire	Wire
21W36	13.8	560							

Appendix C

Transformer Loading Charts

(In Per Unit)

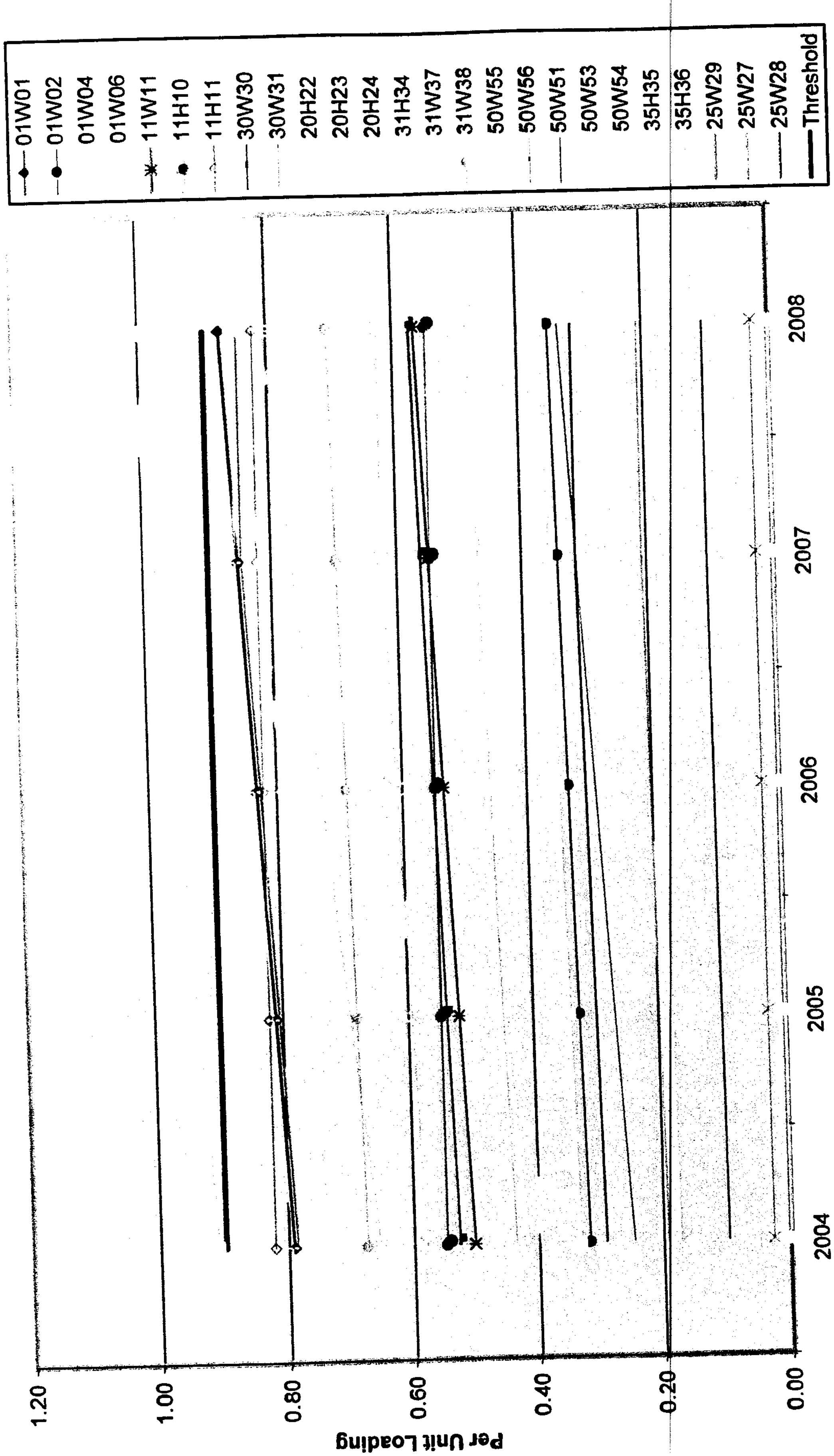

FG&E Transfomer Loading (Summer)
Per Unit Loading
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2004
2005
2006
2007
2008
Summer of
Beech 13.8kV
Canton 4kV
Canton 13.8kV
Lunenburg 13.8kV
Nockege 4kV
Pleasant 4kV
Pleasant 13.8kV
Princeton T2 13.8kV
Princeton T3 13.8kV
Rindge 4kV
River 13.8kV
Sawyer Passway T1 13.8kV
Sawyer Passway T2 13.8kV
South Fitchburg 4kV
Summer 13.8kV
Townsend 13.8kV
West Townsend 13.8kV
Threshold

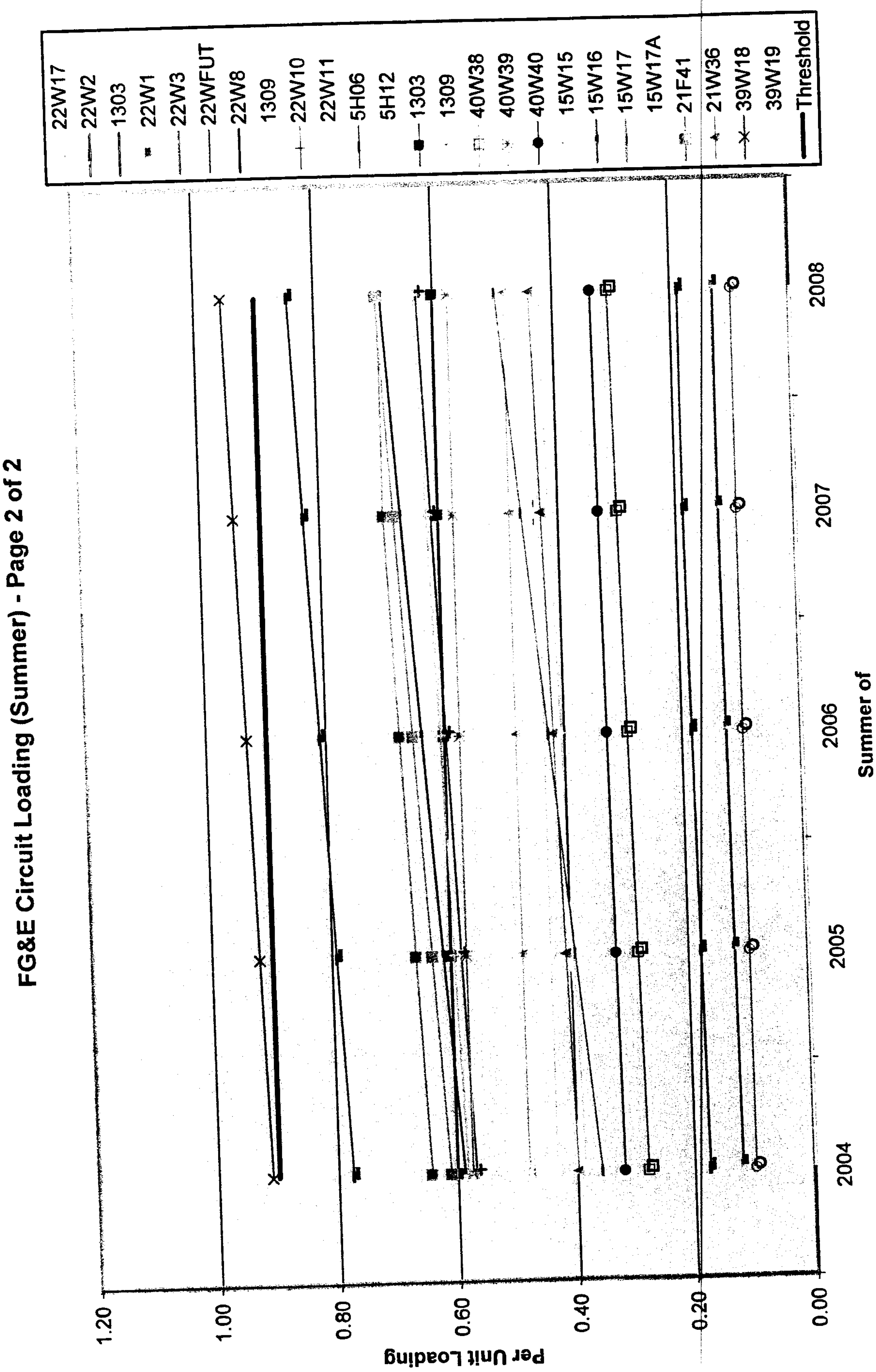

FG&E Transfomer Loading (Winter)
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
03/04
04/05
05/06
06/07
07/08
Winter of
Beech 13.8kV
Canton 4kV
Canton 13.8kV
Lunenburg 13.8kV
Nockege 4kV
Pleasant 4kV
Pleasant 13.8kV
Princeton T2 13.8kV
Princeton T3 13.8kV
Rindge 4kV
River 13.8kV
Sawyer Passway T1 13.8kV
Sawyer Passway T2 13.8kV
South Fitchburg 4kV
Summer 13.8kV
Townsend 13.8kV
West Townsend 13.8kV
Threshold

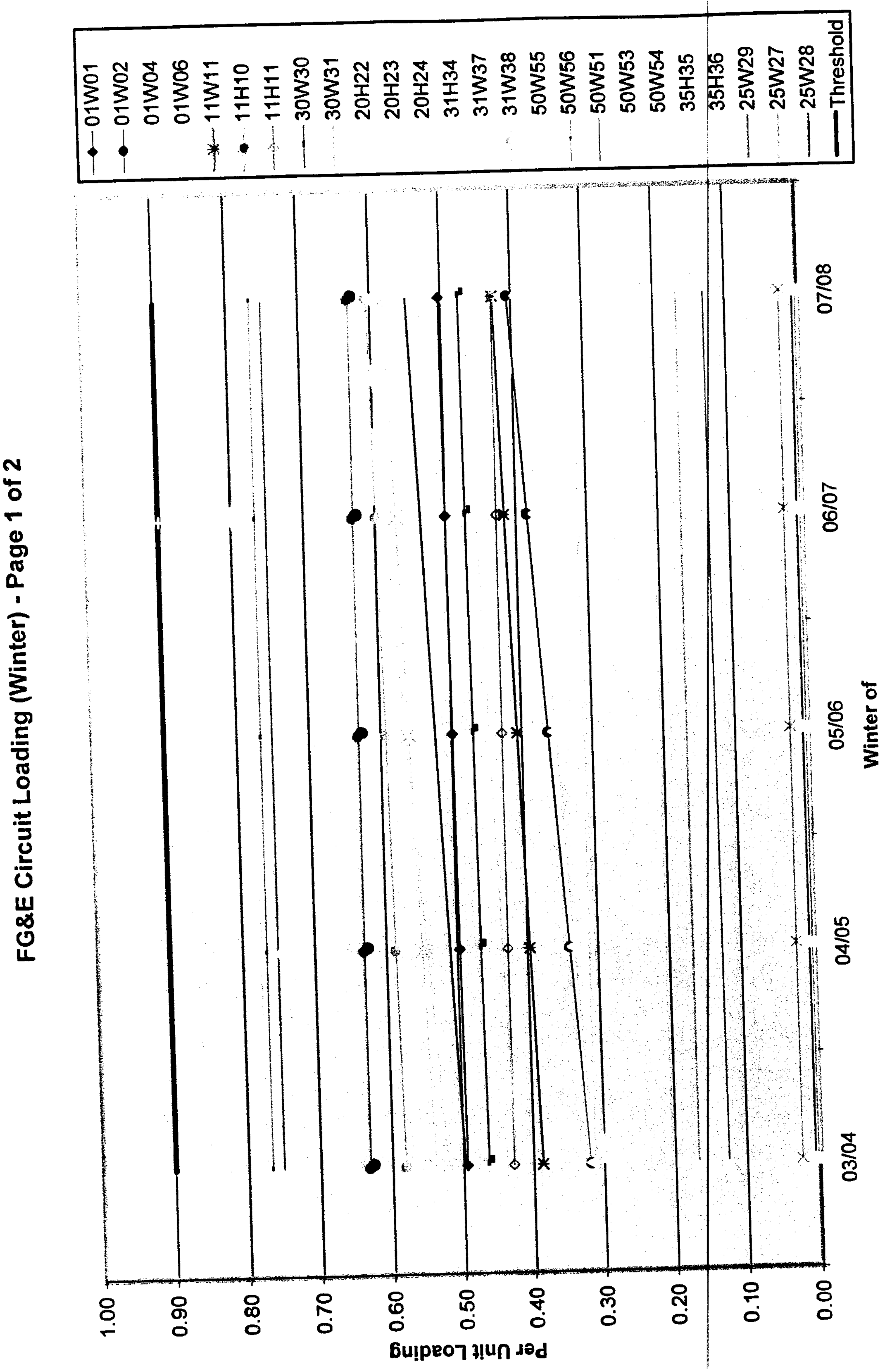
Appendix D

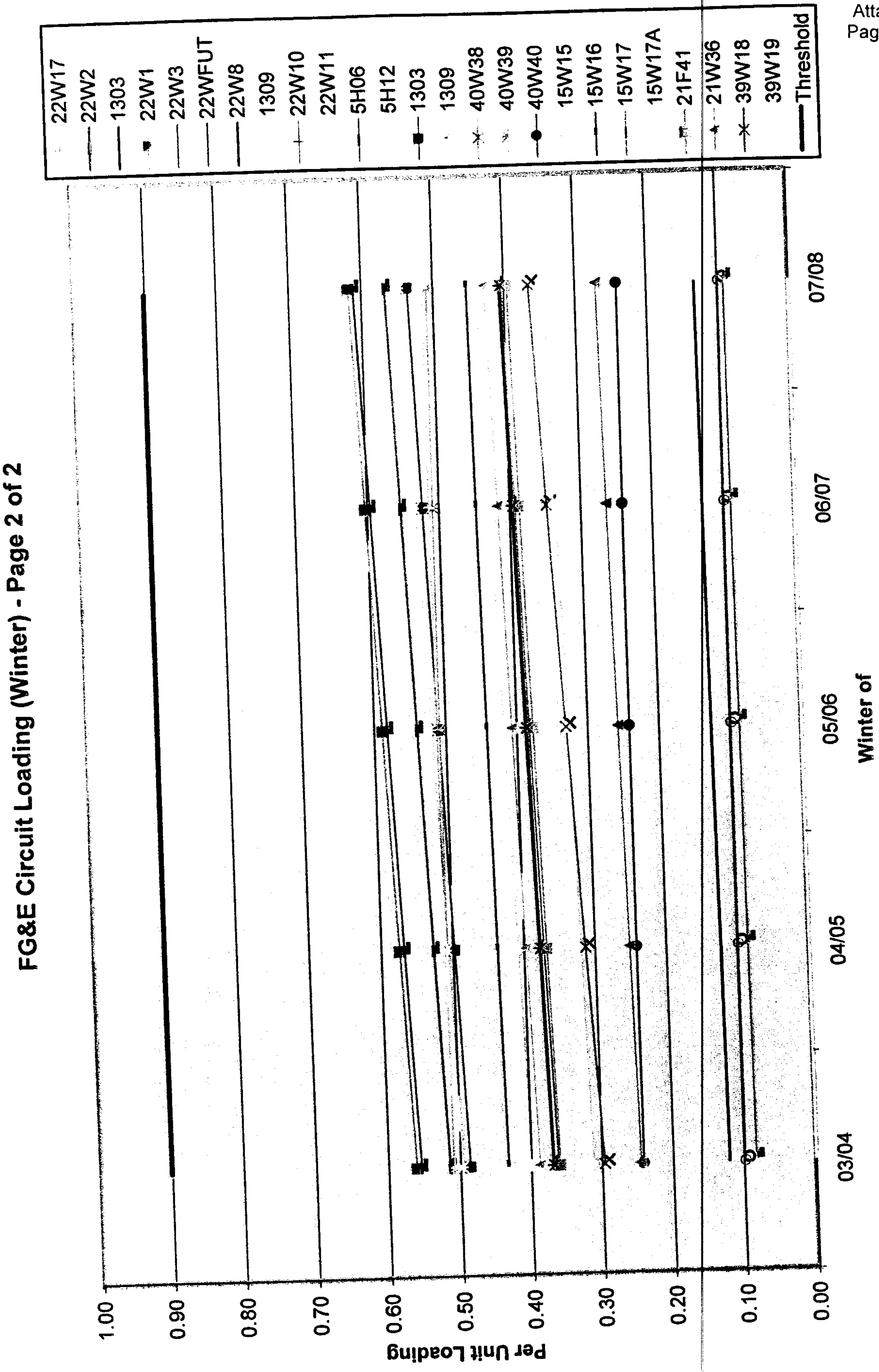
Circuit Loading Charts
(In Per Unit)

FG&E Circuit Loading (Summer) - Page 1 of 2




FG&E Circuit Loading (Summer) - Page 2 of 2
Per Unit Loading
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2004
2005
2006
2007
2008
Summer of
22W17
22W2
1303
22W1
22W3
22WFUT
22W8
1309
22W10
22W11
5H06
5H12
1303
1309
40W38
40W39
40W40
15W15
15W16
15W17
15W17A
21F41
21W36
39W18
39W19
Threshold


FG&E Circuit Loading (Winter) - Page 1 of 2
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
03/04
04/05
05/06
06/07
07/08
Winter of
01W01
01W02
01W04
01W06
11W11
11H10
11H11
30W30
30W31
20H22
20H23
20H24
31H34
31W37
31W38
50W55
50W56
50W51
50W53
50W54
35H35
35H36
25W29
25W27
25W28
Threshold

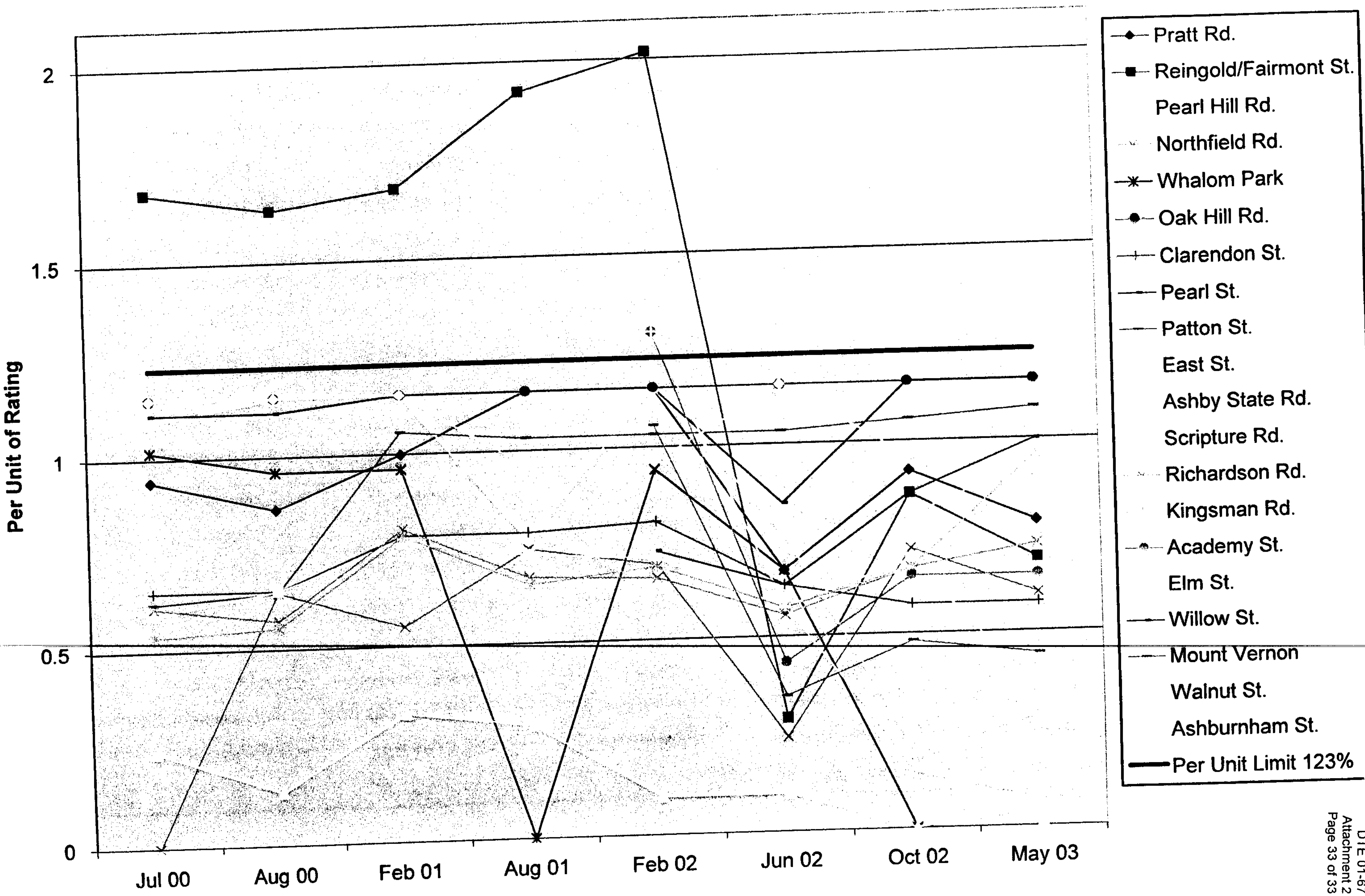

FG&E Circuit Loading (Winter) - Page 2 of 2
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
03/04
04/05
05/06
06/07
07/08
Winter of
22W17
22W2
1303
22W1
22W3
22WFUT
22W8
1309
22W10
22W11
5H06
5H12
1303
1309
40W38
40W39
40W40
15W15
15W16
15W17
15W17A
21F41
21W36
39W18
39W19
Threshold

Appendix E

Stepdown Transformer Loading Chart

(In Per Unit)

FG&E Stepdown Transformer Loading (Historical)



ATTACHMENT 3

UNITIL ELECTRIC SYSTEM PLANNING GUIDELINES

Unitil

Unitil Service Corp.

Electric System Planning Guide

Unitil Service Corp.

Original Issue: April 2000
Revised: December 19, 2003

TABLE OF CONTENTS

1 OBJECTIVE

The objective of this guide is to define study methods and design criteria used to assess the adequacy of Unitil transmission, subtransmission, and substation systems; and to provide guidance in the planning and evaluation of modifications to these systems. The purpose is to ensure appropriate and consistent planning and design practices to satisfy applicable criteria and reasonable performance expectations.

2 INTRODUCTION

All Unitil facilities which are part of the Bulk Power System (Pool Transmission Facilities, PTF) shall be designed in accordance with the latest versions of the Northeast Power Coordinating Council (NPCC) policies, the New England Power Pool (NEPOOL) standards, and all applicable Unitil policies. The fundamental guiding documents are the "Basic Criteria for Design and Operation of Interconnected Power Systems" (NPCC Document A2), the "Reliability Standards for the New England Power Pool" (NEPOOL Document PP3), and this document.

All Unitil facilities which are not considered PTF but are part of the Unitil systems shall be designed in accordance with the latest version of this document.

Detailed design of facilities may require additional guidance from industry or technical standards which are not addressed by any of the documents referenced in this guide.

Systems should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- Utilization of standard components to facilitate availability of spare parts
- Minimization of post contingency switching operations
- Minimization of the use of Special Protection Systems (SPS)

<u>Regulatory Requirements</u>

All Unitil facilities shall be designed and operated in accordance with all applicable state regulatory requirements as specified in the State of New Hampshire's "Code of Administrative Rules" or the Commonwealth of Massachusetts "Code of Massachusetts Regulations."

3 PLANNING CRITERIA

Unitil transmission, subtransmission, and substation systems should be planned and designed for safe, economical and reliable performance, with consideration for normal and reasonably foreseeable contingency situations, load levels, and generation.

3.1 Allowable Equipment Loading

Thermal ratings for system equipment are established to obtain the maximum use of the equipment accepting some defined, limited loss of life or loss of strength. These ratings are based on the Unitil "Electrical Equipment Rating Procedures Guide". The principal variables used to derive these ratings include specific equipment physical parameters and design, maximum allowable operating temperatures, seasonal ambient weather conditions, and representative daily load cycles.

Normal ratings describe the allowable loading to which equipment can operate for normal, continuous load cycling up to peak demands at the indicated **Normal Limit**. Emergency ratings allow brief operation of equipment to higher peak demand limits for emergency situations.

The following listing summarizes Unitil equipment thermal ratings:

Rating	Allowable Duration before Relief
Summer Normal Limit	continuous
Summer Long-Time Emergency (LTE) Limit	12 hours
Summer Short-Time Emergency (STE) Limit	15 minutes
Winter Normal Limit	continuous
Winter Long-Time Emergency (LTE) Limit	4 hours
Winter Short-Time Emergency (STE) Limit	15 minutes

Equipment loaded at or below its **Normal Limit** is operating within normal loading conditions. Equipment loaded above its **Normal Limit** is operating at emergency loading conditions, and may be experiencing higher than normal loss of life or loss of strength.

Equipment loaded above its **Normal Limit** and at or below its **Long-Time Emergency Limit** is operating at a long-time emergency load level. Long-time emergency loading may be sustained for a single, non-repeating load cycle where the **Normal Limit** is exceeded for no more than the allowable duration.

Equipment loaded above its **Long-Time Emergency Limit** and at or below its **Short-Time Emergency Limit** is operating at a short-time emergency load level. Short-time emergency loading must be relieved to normal or LTE conditions within 15 minutes. Unitil systems should be planned and designed to avoid short-time emergency loading. However, it is acceptable for equipment to be loaded to short-time emergency conditions following a loss-of-element contingency, provided automatic or remote actions are in place to relieve the loading within the specified time.

Equipment loaded beyond its **Short-Time Emergency Limit** is operating at a **Drastic Action Level (DAL)**, and immediate relief is required including the shedding of load if necessary. If a facility operates at this level for more than five minutes, equipment may suffer unacceptable damage. Unitil systems shall not be planned for equipment to reach DAL loadings.

3.2 Allowable System Voltages

System voltage ranges are established to obtain adequate operating voltages for system customers, maintain proper equipment performance, avoid over-excitation of transformers or under-excitation of generators, and preserve system stability. Unitil systems should be planned and designed to sustain steady-state operating voltages at **Non-Distribution points** within a minimum limit of 90% of nominal (108 V on a 120 V base) and a maximum limit of 105% of nominal (126 V on a 120 V base). Unitil systems should be planned and designed to sustain steady-state operating voltages at **Distribution points** within a minimum limit of 97.5% of nominal (117 V on a 120 V base) and a maximum limit of 104.2% of nominal (125 V on a 120 V base).

In this context, **Non-Distribution points** indicate locations that are not direct supply outputs for distribution circuit loads. Most transmission and subtransmission lines are **Non-Distribution**, as are most substation facilities where the voltage regulation is applied after the low-side bus (i.e. at the individual distribution circuit terminals).

Correspondingly, **Distribution points** indicate locations that are direct supply outputs for distribution circuit loads. This may be, for example, at unregulated distribution circuit or customer taps off of subtransmission lines, or at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

It is acceptable for steady-state voltage excursions beyond these limits to occur immediately following a contingency event and while corrective actions are in progress. However, Unitil systems should be planned and designed to limit the extent and duration of such excursions. Furthermore, Unitil systems shall not be planned to accept unchecked voltage collapse.

There are no design limits on the amount of change in operating voltages from initial pre-contingency to immediate post-contingency levels.

3.3 System Configuration

Unitil systems shall be planned and designed to meet applicable criteria utilizing specific normal and emergency configurations of system elements.

The **Normal Configuration** shall describe the intended arrangement of the system when all normally in-service elements are available. Unitil systems should be planned and designed to operate within normal equipment ratings and voltage ranges when in the **Normal Configuration** at all normally anticipated load levels.

The arrangement of system elements may be temporarily altered to a non-emergency configuration for routine operating and maintenance purposes. An acceptable non-emergency configuration should also satisfy normal ratings and voltages. It is not a requirement that Unitil systems be planned or designed for every possible non-emergency configuration.

A **Contingency Configuration** describes a modified arrangement of the system in response to emergency conditions. Unitil systems should be planned and designed to be promptly arranged into prescribed **Contingency Configurations** when necessary to attain acceptable conditions following specific contingent emergencies, and to operate within specified equipment ratings and voltage ranges when in these configurations.

3.4 System Load

Unitil systems shall be planned and designed to meet applicable criteria up to specific normal and emergency load levels.

3.4.1 Peak Design Load

The **Peak Design Load** describes the benchmark load level that system adequacy is measured against. It shall be the highest anticipated coincident, active (real) power demand of all system customers, plus associated system losses, plus adjustments deemed reasonable to address forecasting uncertainties. The **Peak Design Load** is the actual load and losses to be supplied, and not the net sum of power flows at system boundaries after being offset by internal sources. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges at load levels up to the established **Peak Design Load**.

3.4.2 Extreme Peak Load

Load levels above the established **Peak Design Load** are considered a contingency event under which emergency conditions may be accepted. The **Extreme Peak Load** describes a maximum foreseeable load level benchmark, such as might occur during extraordinary, one-in-ten-year temperature extremes. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges at load levels up to the established **Extreme Peak Load** with all elements available.

3.5 Load Power Factor

Load Power Factor in each area should be consistent with the limits set by the requirements developed under NEPOOL criteria, rules, and standards #30 (CRS-30) for that area.

3.6 System Generation

The operation of generating plants not directly under Unitil control may be determined by a competitive market bidding system where plant availability and dispatch may not include consideration of system support or reliability needs. Unitil systems shall be planned and designed to meet applicable criteria under reasonably foreseeable generation dispatch, taking into account uncertainties in unit status and future availability.

3.6.1 Generation Dispatch

For planning purposes, typical historical performance for each unit may be used as the initial basis for generation dispatch assumptions. These assumptions should take into account factors for seasonal variations, demonstrated forced-outage rates, operating limits, and expected performance during system disturbances.

The planning and operation of generating plants outside of Unitil systems is not typically within the scope of Unitil planning requirements unless they have a direct impact on system adequacy. The impact of generation inside or within the immediate vicinity of Unitil systems should be taken into account. Unitil systems should be planned and designed to operate within normal equipment ratings and voltage ranges during the outage of any utility-owned generating plant.

3.6.2 Non-Utility Generation

The adequacy of system infrastructure to meet Unitil's end-use load obligations necessitates that it be self-sufficient to a certain extent from internal, non-utility generation. Unitil systems are to be planned and designed to operate within specified equipment ratings and voltage ranges with at least one-half of all internal, non-utility generating facilities that presently exist being out of commission in the future.

3.6.3 Generation Rejection or Ramp Down

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a system disturbance. As a general practice, generation rejection or ramp down should not be included in the planning and design of the Unitil systems.

3.6.4 Priority

Serving load has priority over generation. Therefore, if there is an option to trip generation or trip load, the plan will be to trip generation.

3.7 Normal Conditions

Unitil systems shall be planned and designed to operate within normal equipment ratings and voltage ranges for the following normal conditions:

- all normally in-service elements available, and
- load levels up to the established **Peak Design Load**, and
- typical seasonal generation dispatch.

Additionally, the impact of the following generation conditions should be taken into account:

- outage of any utility-owned generating plant inside or within the immediate vicinity of the system, and
- outage of up to 50% (cumulative output) of internal non-utility generating plants.

3.8 Contingency Conditions

Unitil systems shall be planned and designed to meet applicable criteria for specific, pre-determined emergency scenarios.

Design Contingencies describe the pre-determined emergency scenarios that system adequacy is measured against. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges following actions in response to the following **Design Contingencies**:

- loss of any **Non-Radial Line** element, or
- loss of any **Radial Line** element with no backup tie, or
- loss of any **System Supply Transformer**, or
- **Extreme Peak Load** with all elements available.

3.9 Allowable Loss of Load

The objective of planning and designing the system to meet **Design Contingency** criteria is to utilize system elements up to their maximum allowable capabilities to carry or restore as much load as possible. It is understood and accepted that many system fault or equipment failure events, including loss-of-element **Design Contingencies**, may result in the temporary loss of customer load until damaged components are isolated and restoration switching is performed. However, limited loss of customer load for more extended periods of time are acceptable design compromises for specific circumstances where other alternatives are not practical or economical.

3.9.1 Loss-of-Element Contingency

To provide continuity or immediate restoration of service to all portions of system load for all reasonably foreseeable contingencies requires fixed infrastructure with spare capacity or redundancy for each element. This level of design may be inefficient and cost-prohibitive to cover the contingent loss of certain major elements. The loss of limited portions of system load for limited periods of time may be tolerated under defined circumstances as part of prudent, cost-effective alternatives to fixed infrastructure. These alternatives are traditionally either of two choices: (1) the interruption of load while repairs are being made to an element that cannot be backed up; or (2) the interruption of load while mobile or spare equipment is made available from another location, transported and placed into service where needed.

The Unitil system is designed to accept loss of load during the following specifically identified **Design Contingencies**, subject to the indicated conditions and limits:

Table 3.9.1-1 Allowable Loss of Load

Design Contingency	Allowable Loss of Load	Allowable Duration
Loss of a radial line element with no backup tie	≤ 30 MW	≤ 24 hours
Loss of a system supply transformer	≤ 30 MW	≤ 24 hours

Under these contingencies, it is understood that remaining system elements will be utilized up to their maximum allowable capabilities to carry or restore as much load as possible. Allowable Loss of Load refers to a collection of customers within the system that cannot be restored after these automatic or manual actions. This load is the peak coincident demand of this collection of customers, and not the net sum of power flow that may be seen if offset by sources within the affected portions of the system. The allowable impact is limited to these affected customers, not the overall load level at any given time. If actual load at the time is not at peak conditions, it is not acceptable to extend interruptions to a wider collection of customers by summing the demands at that time up to the same numerical limit.

3.9.2 Extreme Circumstances

Widespread outages or catastrophic failures resulting from contingencies more severe than defined **Design Contingencies** may acceptably result in loss of customer load in excess of the limits given here.

3.9.3 Regional Load Shed

NEPOOL and NPCC require that each member have load shedding capability to prevent a widespread system collapse. The types of conditions that could result in these emergencies are unusually low frequencies, equipment overloads, or unacceptable voltage levels in an isolated or widespread area of New England. These conditions may require load shedding. The specific requirements associated with the load shedding are specified in NEPOOL Operating Procedure No. 7 "Action In An Emergency".

3.10 Exceptions

These planning criteria do not apply if a customer receives service from Unitil and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, Unitil has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

Unitil is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, Unitil does not have to provide redundant transmission supplies.

4 PLANNING STUDIES

4.1 Basic Types of Studies

System planning studies based on steady-state power flow simulation shall be routinely conducted to assess conformance with the criteria and standards cited in this guide. These studies will review present and future anticipated system conditions under normal and contingency scenarios. The scale and composition of the Unitil electric system does not typically warrant routine analysis of its dynamic behavior. Transient stability analyses (and other forms of study) are conducted as needs arise.

4.2 Study Period

The lead-time required to plan, permit, license, finance, and construct transmission, subtransmission or substation upgrades is typically between one and ten years depending on the complexity of the project. As a result, system planning studies should examine conditions at various intervals covering a period of ten-years to identify potentially long-term projects.

4.3 Modeling and Assessment for Steady-State Power Flow

The modeling representation for steady-state power flow simulation should include the impedance and admittance of lines, generators, reactive sources, and any other equipment, which can affect power flow or voltage (e.g. capacitors or reactors). The representation should include voltage or angle taps, tap ranges, and control points for fixed-tap, load-tap-changing, and phase shifting transformers.

Specific issues related to the study, which need to be addressed, are discussed below.

4.3.1 Element Ratings

Thermal ratings of each load-carrying element in the system are determined to obtain the maximum use of the equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers and switches). Models will include three (3) rating limits for each season's case:

Summer models- Summer Normal, Summer LTE, and Summer STE.
Winter models - Winter Normal, Winter LTE, and Winter STE.

4.3.2 Modeled Load

Load development is extremely important to the creation of an effective model. The summer and winter forecasted **Peak Design Loads** and **Extreme Peak Loads** should be obtained annually from the appropriate department for a period of ten years. Modeled loads for each load center should be developed in sufficient detail to distribute the active and reactive coincident loads (coincident with the system's total peak load) throughout the system such that the net effect of loads and losses matches expected power flows and the overall **Peak Design** or **Extreme Peak** load for each case.

4.3.3 Load Levels

To evaluate the sensitivity to daily and seasonal load cycles, studies may require modeling several load levels. Minimum requirements call for study of peak load levels (**Peak Design** or **Extreme Peak**). Where high voltage issues or unusual reactive power flows are a concern, or the degree of consequences and exposure to risks must be quantified, lesser load levels may be studied. The basis for the these loads can be either summer or winter conditions, whichever is the worst case scenario for the system. In some areas, both seasons should be studied.

4.3.4 Balanced Load

Balanced, three-phase, 60 Hz ac loads should be assumed at each load center unless specifically identified by an area or circuit study. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load of the other phases.
- The voltage unbalance between the phases, measured phase–to–phase, is less than 3%.
- Harmonic voltage distortion is within limits recommended by the current version of IEEE Std. 519.

4.3.5 Reactive Compensation

Reactive compensation should be modeled as it is designed to operate on the system and, when appropriate, located on the low voltage side of substation transformers. Reactive compensation on distribution feeders and circuits are assumed to be included within the modeled loads.

4.3.6 Generation Dispatch

Analysis of system sensitivity to variations in generation dispatch is necessary during a study. The intent is to test the adequacy of the Unitil system as much as can be reasonably anticipated against the end-use loads which it is obligated to serve.

The basis for modeling should begin with initial assumptions of generating unit outputs at their typical seasonal levels. Cases may then be modified to reflect intended criteria and assumptions for future conditions.

In modeling the system, one-half of internal, non-utility generation should be considered as being in commission and operational for the future study period. This may be modeled conservatively by taking the most significant facilities for a portion of the system out of service until the sum total of internal non-utility generation has been reduced by at least fifty percent (50%) from their typical historical output. Remaining units may be modeled at their historical output. This may result in additional units being reduced or off-line if that has been their typical history (e.g. hydro generation during periods of low river flow).

4.3.7 Facility Status

Initial conditions assume all existing facilities normally connected to the system are available and operating as designed or expected.

Studies should not consider presently planned improvements or modifications to be assured to be implemented for future system models. Instead, these improvements should be updated and reaffirmed through the study process as being necessary and the most cost-effective options available. Risks, consequences, and exposure levels should be determined in the event that projects are not completed as planned.

4.4 Modeling For Stability Analysis

4.4.1 Dynamic Models

Dynamic models are required for generators and their associated equipment, HVdc terminals, and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained in cooperation with NEPOOL and NPCC.

4.4.2 Load Level and Load Models

Stability studies within NEPOOL typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed with a bulk power system load level of 45% of peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch within a specific area or system.

System loads within NEPOOL are usually modeled as constant admittances for both active and reactive power, but other load models can be used as needed. Loads outside NEPOOL are modeled consistent with the practices of the individual areas. Appropriate load models for other areas are available through NEPOOL and NPCC.

4.4.3 Generation Dispatch

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched economically. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

4.5 Addressing System Deficiencies and Constraints

System studies should clearly identify results that fail to satisfy criteria or constrain performance. To the extent that supporting information is available, these deficiencies or constraints should be quantified in terms of severity, extent of impact, duration and periods of exposure.

4.6 Development and Evaluation of Alternatives

If the performance or reliability of the forecasted system does not conform to the applicable criteria, then alternative solutions based on performance, reliability, technical preference, economics, and capacity need to be developed and evaluated. The evaluation of alternatives leads to a recommendation, which is summarized concisely in a report.

4.6.1 Performance

The system performance with the proposed alternatives should meet or exceed all applicable planning criteria.

4.6.2 Reliability

This guide assesses reliability deterministically by defining conditions which the system must be capable of withstanding. This deterministic approach is consistent with NEPOOL and NPCC practice. The system is designed to meet these deterministic criteria to promote reliability and efficiency.

The level of reliability provided through this approach may vary on the bulk system. To some degree this is acceptable due to inherent factors such as differences in local area load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, service requirements, and class and vintage of equipment. When the level of reliability provided to an area is significantly lower than other areas, alternatives are developed to improve the reliability.

When assessing local area reliability, the engineer compares the reliability of comparable areas at different locations on the system. This comparison considers factors such as age, condition, style, and failure rates of equipment. The cause of poor reliability also influences the recommended action. Therefore, the engineer must assess the specific conditions affecting the reliability of service to particular customer(s).

If remedial actions are taken, historical performance data over an appropriate period of time may need to be re-established prior to assessing the need for additional remedial actions.

4.6.3 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement.

4.6.4 Economics

Initial and future investment cost estimates should be prepared for each alternative identified during the course of a study. An engineering economic analysis, as defined in the Unitil Economic Evaluation Procedures, is required to compare the total unit cost of each alternative. The analysis should include the annual charges on investments, losses, and all other expenses related to each alternative.

4.6.5 Capacity

All equipment should be sized based on economics, operating requirements, standard sizes, and engineering judgment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a rough guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without additional major modifications for at least ten (10) years.

4.7 Recommendation

Every study that identifies potential violations of design criteria shall propose recommended actions. The recommended actions should be based on factors such as the forecasted performance, reliability, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, environmental impacts of facilities, and complexity to license and permit.

4.8 Reporting Study Results

A system planning study should culminate in a professional report clearly describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

5 TERMINOLOGY

Bulk Power System

The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant effect outside the local area.

Contingency

An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Contingency Configuration

A modified arrangement of the system to attain acceptable conditions following a contingency event.

Design Contingency

A pre-determined emergency scenario that system adequacy is measured against.

Distribution Point

Locations on a system that are direct supply outputs for distribution circuit loads. This may be, for example, at unregulated distribution circuit or customer taps off of subtransmission lines, or at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

Drastic Action Level (DAL)

Any loading of an element above its STE limit. DAL loading requires immediate relief, including the shedding of load if necessary, to avoid the likelihood of unacceptable or catastrophic damage to equipment..

Element

Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, phase angle regulating transformer, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its current transformer(s).

Extreme Peak Load

A maximum foreseeable load level benchmark, such as might occur during extraordinary, one-in-ten-year temperature extremes.

Interface

A collection of transmission lines connecting two areas of the transmission system.

Load Cycle
Refers to the varying facility loading over a 24-hour period.

Long-Time Emergency (LTE) Limit, Summer or Winter
Allowable peak loading to which equipment can operate for a single, non-repeating load cycle due to emergency circumstances, accepting the possibility of higher than normal loss of life or loss of strength.

Loss of Load
Loss of service to one or more customers excluding automatic switching time.

NEPOOL
The New England Power Pool, formed in 1971, is a voluntary association of electric utilities in New England who established a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region.

Non-Distribution Point
Locations on a system that are not direct supply outputs for distribution circuit loads. Most transmission and subtransmission lines are non-distribution, as are most substation facilities where the voltage regulation is applied after the low-side bus (i.e. at the individual distribution circuit terminals).

Non-Radial Line
A transmission or subtransmission line, or portion of a line, with more than one possible sending end. A non-radial line may operate radially by being open at one or more ends or intermediate switching locations. However, a radially operating line is still considered non-radial if it has been designed with the intent of utilizing its alternate sending ends to carry or deliver power.

NPCC
The Northeast Power Coordinating Council is an electric regional reliability council, which was formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. The NPCC area includes the following U.S. states and Canadian provinces: Massachusetts, Connecticut, Rhode Island, New York, Vermont, New Hampshire, Maine, Ontario, Quebec, New Brunswick, and Nova Scotia.

Normal Configuration
The intended arrangement of a system when all normally in-service elements are available.

Normal Limit, Summer or Winter
Allowable peak loading to which equipment can operate during normal, continuous load cycling and prescribed seasonal conditions.

Peak Design Load

The benchmark load level that system adequacy is measured against. The **Peak Design Load** is the highest anticipated coincident, active (real) power demand of all system customers, plus associated system losses, plus adjustments deemed reasonable to address forecasting uncertainties. It is the actual load and losses to be supplied, and not the net sum of power flows at system boundaries after being offset by internal sources.

Radial Line

A transmission or subtransmission line, or portion of a line, with only one effective sending end and no back up ties to carry or deliver power.

Scheduled Switching

Any planned switching which is scheduled in advance of any work. This does not include work that occurs as a result of a contingency.

Short-Time Emergency (STE) Limit, Summer or Winter

One-time peak loading which can be sustained by equipment for up to 15 minutes while corrective actions are underway following a contingency emergency, and accepting the likelihood of higher than normal loss of life or loss of strength.

Special Protection Systems

A Special Protection System (SPS) is a protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding is not considered an SPS.

System Supply Transformer

Transformers that deliver power into a system from its external transmission supply.

System

The collection of electric transmission, subtransmission and substation elements that receive electric power supplied from internal and external sources and transport and deliver it to distribution systems. The system is generally a continuous infrastructure in a certain operating area.

Unitil owns and operates systems in three areas: Unitil Energy Systems – Capital (in the region of Concord, NH), Unitil Energy Systems – Seacoast (in the region of Exeter and Hampton, NH), and Fitchburg Gas and Electric Light (Fitchburg, MA).

Transfers

The flow of electrical power across a transmission circuit or interface.

Table 1. Design Guideline Summary

Design Condition	Load Level	Generation	Allowable Element Loading Limit[1]	Allowable Element Loading Duration	Allowable Loss of Load Limit	Allowable Loss of Load Duration
Normal Configuration – all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ up to half of internal, non-utility generating units out of service	≤ Normal	---	none	---
Normal Configuration – outage of generating plant			≤ Normal	---	none	---
Contingency Configuration – loss of non-radial line			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
Contingency Configuration – loss of radial line (no backup tie)			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Contingency Configuration – loss of system supply transformer			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Extreme Peak – all elements in service	≤ Extreme Peak Load		≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

(S) = Summer load cycle, (W) = Winter load cycle

Table 2. Voltage Range Summary

Condition	Low Limit (p.u.)	High Limit (p.u.)
Non-Distribution points	0.90	1.05
Distribution points	0.975	1.042

1 STE loading is acceptable following a loss-of-element contingency, provided actions are available to relieve the loading within 15 minutes.

ATTACHMENT 4

UNITIL EQUIPMENT RATING PROCEDURES

Unitil

Electrical Equipment

Rating Procedures

Issued: April 4, 2000
Revision 1.0

Unitil

Contents

PREFACE

The rating procedures contained herein are assembled for use by the Unitil Service Corporation. The procedures provide methodology to serve as a guide for the uniform rating of the designated electrical equipment. No warranty, expressed or implied, is made by the contributors or their sponsors.

SECTION I

INTRODUCTION

1.1 Electrical Equipment covered by these procedures

The Transmission and Substation Equipment that is covered by these procedures includes:

- Transformers
- Transmission Line Conductors
- Current Transformers (CT's)
- Breakers, Switches, Circuit Switchers, Regulators, and Series Reactors.

1.2 Required Ratings

Presently, Unitil Service Corp., with a few exceptions, utilizes the same rating procedures for Normal and Emergency conditions as specified by the New England ISO. The capacity of either the line conductor, transformer, and/or terminal equipment, may limit the overall rating. All equipment is assigned ratings for the following system conditions

Summer Normal Peak	Winter Normal Peak
Summer Long Term Emergency - 12 Hours	Winter Long Term Emergency - 4 Hours
Summer Short Term Emergency - 15 Minutes	Winter Short Term Emergency - 15 Minutes
Summer Drastic Action - 5 Minutes (requires immediate action)	Winter Drastic Action - 5 Minutes (requires immediate action)

The Winter Period is defined as October 1 to March 31. The Summer Period is defined as April 1 to September 31.

I. Normal Rating is defined as the rating, adjusted for ambient conditions, which will allow maximum equipment loading without incurring loss of life above design criteria.

II. Emergency Ratings, which exceed normal ratings, may involve loss of life or loss of tensile strength in excess of design criteria.

III. Drastic Action Limits, unlike normal and emergency loading ratings, are limits which immediate action will be taken to prevent damage to equipment.

1.3 Ambient Temperatures and Wind Velocities

Unless otherwise specified, the following table of ambient temperatures should be used for determining equipment ratings:

	Power and Current Transformers		All other Transmission Line Equipment	
	Normal	**Emergency**	**Normal**	**Emergency**
Winter (11/1 to 3/31)	**10°C**	**10°C**	**10°C**	**10°C**
Summer (4/1 to 10/31)	**25°C**	**32°C**	**28°C**	**28°C**

*Wind velocity of 3 fps during the Summer and Winter periods should be assumed where applicable.

The given ambient temperatures have been found by Unitil to be representative of New England conditions following a review of area temperature statistics.

The ambient temperature recommendations were developed taking into consideration the following:

A. Power and Current Transformers

The ANSI Guide for Loading Oil Immersed Distribution and Power Transformers (C57.92) recommends the use of "average maximum daily temperatures" for the month involved in determining normal and emergency ratings. The Guide also recommends the use of a 5°C adder to be conservative. The ambient temperatures indicated in the preceding table are based on the recommendations for determining ambient temperatures set forth in the ANSI Guide including the recommended 5°C adder.

The criteria to be used for developing ambient temperature for current transformers will be the same as power transformers.

B. Transmission Line Conductor

The IEEE Recommended Standard for calculation of Bare Overhead Conductor Temperature and Ampacity Under Steady-State Conditions (ANSI/IEEE Std 738-1986).

1.4 Temporary Ratings

The intent of these procedures is to provide a uniform method of rating line terminal equipment. Temporary ratings will be used until permanent rating calculations are established. The temporary ratings will be based on the manufacturers' continuous ratings.

1.5 Equipment Temperature

Equipment temperatures for normal loading shall be in accordance with industry standards or loading guides where applicable. In cases where no industry approved guides exist for emergency loading, maximum equipment temperatures higher than design values may be allowed for emergency operation, at the discretion of Unitil Service Corp. It is noted that operation at total temperatures above design values may violate manufacturers' warranties and/or may result in undesirable changes in operating characteristics.

1.6 Temperature Measurements

The temperature of line terminal equipment which experience maximum rated loads may be measured with infrared equipment or other appropriate devices during these maximum rated loads.

Ratings based on reliable infrared observations, or any other reliable temperature measurements, obtained under operating conditions, will be considered to take precedence over all other ratings.

1.7 Nonconforming Equipment

Equipment not designed, not manufactured, not installed, or not maintained in accordance with these Procedures is assigned ratings in accordance with the manufacturer's recommendations.

1.8 Assumed Loading Conditions

Where time-temperature relationships for annealing characteristics have been applied, the following estimated hours of operation at allowable equipment temperatures have been assumed, over a 30-year equipment life:

Normal Rating	13,200 hours
Emergency (4-12 hour) Rating	500 hours
Emergency (15 minute) Rating	20 hours
Drastic Action Limit	N/A

These estimates are based on the fact that annealing and loss of strength occur only when a device is operating at or near its emergency rated temperature limits. For most locations on the transmission system, ambient temperature variations together with daily and seasonal cycling of load current will result in conditions where the equipment operates at temperatures considerably lower than rated values, most of the time.

The total duration of operation at emergency temperatures reflects a conservative estimate for the time that the rated elements are expected to operate under contingency conditions. In regards to conductors, the common rule of thumb for loss of tensile strength is to limit the loss to 10 % over the 30-yr equipment life.

1.9 Calculation of Drastic Action Limits

For purposes of calculation, the Drastic Action Limit is defined as the current flow which would cause the circuit component to reach its 15-minute emergency thermal limit, if allowed to flow for five minutes, the following conditions having been assumed:

a. The guidelines as to summer and winter ambient conditions being as described in paragraph 1.2.

b. Pre-disturbance loading of the circuit assumed to be 75% of the normal terminal equipment rating or 75% of the conductor sag limitation, whichever is less, for the appropriate season.

The prescribed "drastic action" is to be whatever immediate action is required to return the circuit loading to the long term emergency rating for the appropriate season, including, but not limited to, tripping of the circuit. The use of five minutes in computing the Drastic Action Limit does not indicate that five minutes, or any other time increment, exists for which current of the calculated magnitude may safely be allowed to flow.

SECTION 2
TRANSFORMERS

2.1 Standards

The ratings described in this section apply only to transformers with nameplate ratings of 100 MVA and below, since the existing loading guides apply only to transformers up to 100 MVA. Loading guides for transformers with nameplate ratings greater than 100 MVA are presently under development. (Project number 756 of the IEEE Transformers Committee has developed "Trial Use Guide for Loading of Mineral Oil Insulated Power Transformers Rated in Excess of 100 MVA"). Permissible loadings for transformers with nameplate ratings above 100 MVA should be developed with the manufacturer on an individual basis.

Transformers are to be rated in accordance with the following listed standards and exceptions to these standards.

a. Transformers are to be rated by use of a PC and one of the computer programs listed in Item 2, or other computer programs which provide equivalent results, except that transformers which are not ANSI Standard transformers are to be assigned ratings in accordance with the manufacturer's recommendations. Many transformers manufactured prior to 1948, and a few modern transformers, are not ANSI Standard transformers.

b. Transformers are not to be loaded beyond the following limits from ANSI Standard Appendix: C57.92 - 1981, "Guide for Loading Oil-Immersed Distribution and Power Transformers" for transformers with 55°C and 65°C average winding rise. The following rating limits have been established.

TRANSFORMER RATING LIMITS

	55°C RISE TRANSFORMER	65°C RISE TRANSFORMER
Max Hottest Spot Temperature	**150°C**	**180°C**
Max Top Oil Temperature	**100°C**	**110°C**
Max Loading on Transformer	**2 x Nameplate**	**2 x Nameplate**

c. Winter and Summer normal ratings are based on the normal daily load cycle and on the maximum twenty-four hour average ambient temperatures. Operation at these ratings continuously results in no more loss of life on the transformer than what is assumed in its life.

d. Winter Emergency – 4 Hours, and Summer Emergency – 12 Hours ratings are to be based on the normal daily load cycle with the emergency load added to the peak period, on the maximum twenty-four hour average ambient temperatures of Section 1, Item 1.3 of these Procedures, and on imposing 1 percent loss of life on the transformer for each daily load cycle during which such an emergency occurs, except as follows:

   1. The amount of loss of life to be imposed on any transformer which is not an ANSI Standard transformer is to be determined, in accordance with the manufacturer's recommendations.

e. Winter and Summer Short Term Emergency – 15 Minute are to be at twice nameplate. No loss of life is considered for the 15 minute emergencies.

f. The short-term emergency ratings are used only when the condition can be corrected and the loading returned to below the long term emergency limit within the prescribed 15 minute time duration.

2.2 Computer Programs

The computer programs listed below are part of these Procedures.

Rating of Two-Winding Transformers Manufactured Prior to 1940
Rating of Two-Winding 55°C Rise Transformers Manufactured After 1940.
Rating of Two-Winding 65°C Rise Transformers.
Rating of Three-Winding Transformers

These computer programs were written in Fortran for execution on a mainframe computer. They have been compiled for use on PC's using the Microsoft Fortran compiler.

SECTION 3
TRANSMISSION LINE CONDUCTORS

3.1 Foreword

The capacity rating calculation procedures are designed to achieve uniformity. In applying any rating procedure, care must be used in deciding on parameters such as ambient air temperature and wind velocity. The parameters recommended in this guide for the use of wind and ambient temperature are as follows:

Summer -	April 1 to October 31 -	37.8°C	3 ft. per second.
Winter -	November I to March 31 -	10°C	3 ft. per second.

It must be recognized that at any given moment temperature and wind conditions will almost certainly be different from the above; therefore, the use of ratings based on the above must be clearly defined. During actual operation, a revised rating may be used based on atmospheric conditions existing at the time of the required emergency loading. The value for the transmission line summer ambient temperature is mandated by the Massachusetts Department of Public Utilities, CMR 220, 125.23 (3).

3.2 Recommendations

The following guidelines are recommended:

a. Normal and Long-Time Emergency conductor ratings should be obtained by use of the Unitil Service Corp. Basic computer program (AMPACIT2.BAS) titled "IEEE METHOD FOR CALCULATION OF BARE OVERHEAD CONDUCTOR TEMPERATURE", based on IEEE Std 738.

b. Short-Time Emergency ratings and Drastic Action Limits should be obtained by use of a computer program capable of evaluating transient thermal conditions. A computer program to calculate these ratings is under evaluation at Unitil Service Corp.

c. Input parameters for conductor diameter, wind velocity, emissivity, absorbtivity, ambient temperature, and conductor resistance should be as specified or obtained by methods specified herein.

d. Equation constants used in the rating program should be as specified herein.

e. Conductor ratings should include:

Summer rating
Summer Long-term Emergency
Summer Short-term Emergency
Summer Drastic Action Limit
Winter rating
Winter Long-term Emergency
Winter Short-term Emergency
Winter Drastic Action Limit

f. The following values for equation parameters are recommended for use.

Parameter Recommendations

Parameter	Name	Value
D	Conductor Diameter	As required
E	Emissivity Factor	0.75
A	Absorbtivity Factor	0.50
R	Conductor Resistance	As required
Ta	Ambient Temperature	37.8°C Summer 10°C Winter
Tc	Conductor Temperature	
	(Normal Rating)	80°C
	(Long-time Emergency Rating)	100°C
	(Short-time Emergency Rating)	120°C
V	Wind Velocity	3.0 fps

3.3 Application of Ratings

The long-time Emergency and the short-time emergency ratings are to be used for contingency conditions only. Contingency conditions refer to outages of system components as a result of switching or unplanned events. The short-term emergency ratings are used only when the condition can be corrected and the loading returned to long-time emergency loading within the prescribed 15 minute time duration.

SECTION 4

BREAKERS, SWITCHES, CIRCUIT SWITCHERS, RECLOSERS, AND SERIES REACTORS

4.1 Standards

Breakers, switches, circuit switchers, regulators, and series reactors are to be assigned ratings in accordance with the manufacturer's recommendations. These ratings are typically the nameplate ratings of the device.

SECTION 5

CURRENT TRANSFORMERS

5.1 Standards

Current transformers are to be rated in accordance with the following procedures.

5.2 Example

The following assumptions and table have been prepared for the sample current transformer using the methods presented in the following guide.

1. The sample current transformer is an independent, oil filled, current transformer, with thermal rating factor of 1.5.

2. Ambient temperatures:

	Normal	Emergency
Winter	0°C	N/A
Summer	30°C	N/A

3. Accuracy and thermal capability of the secondary circuit and the secondary devices is satisfactory at the ratings in the following table.

LOADABILITY MULTIPLIERS
TO BE APPLIED TO NAMEPLATE RATING

	WINTER	SUMMER
Normal	1.8	1.5
Emergency	N/A	N/A

5.3 GUIDE FOR LOADING CURRENT TRANSFORMERS - Unitil Service Corp.

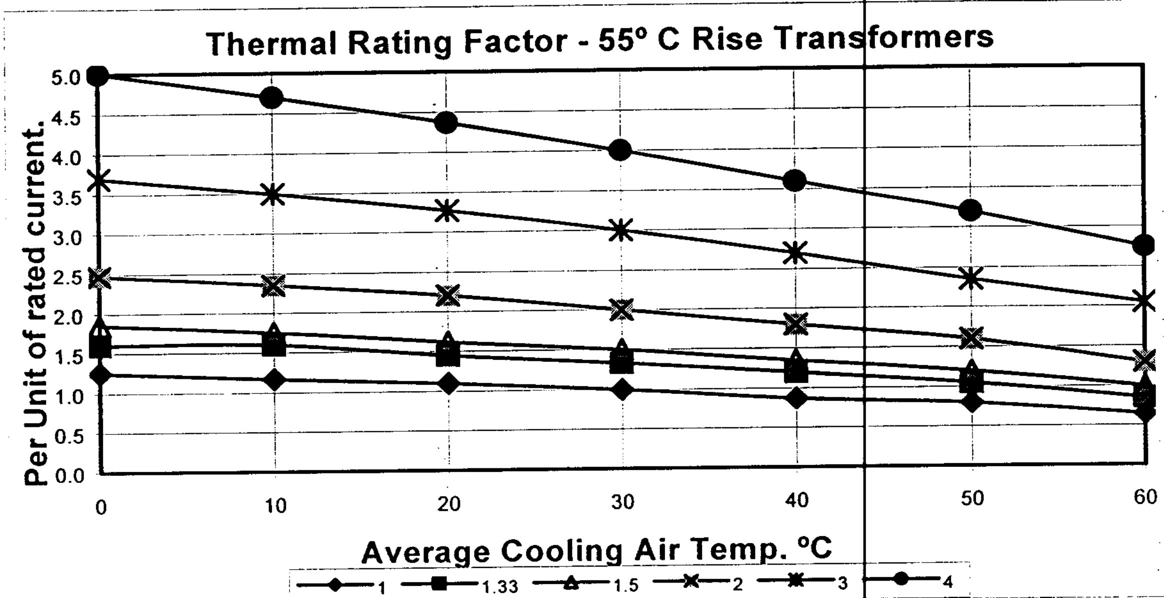
I. Independent Current Transformers –

These are current transformers which are purchased and installed as independent units.

A. Normal and Emergency Continuous Capability – The normal and emergency continuous capability of a current transformer depends on its thermal rating factor and the average cooling air temperature. At the present time the normal and emergency ratings are the same. The rating can be found by choosing the appropriate thermal rating factor and average ambient temperature in Curve 1, (reproduction of Figure 6 of IEEE Standard C57.13-1978) and then reading the per unit of rated current at the left of the curve.

Design temperature limits will not be exceeded if this loading procedure is followed.

Curve #1



II. Internal Bushing Current Transformers –

These are current transformers which use the current-carrying parts of major equipment as their primary windings and are usually purchased as integral parts of such equipment. On a multi-ratio transformer, the secondary winding is tapped.

A. Normal Continuous Capability - Most manufacturers state that internal bushing current transformers furnished with a piece of equipment have thermal capabilities which equal the capability of the equipment.

1) For a single-ratio or multi-ratio internal bushing current transformer operating at a nominal primary current rating equal to the nameplate rating of the equipment with which it is used, the current transformer should be considered to have the same thermal capability as the equipment.

2) For a single-ratio internal bushing current transformer with a rating less than that of the equipment in which it is installed, the calculated equipment capability should be reduced by the factor

3)

$$\sqrt{I_{ct} / I_e}$$

Where I_{ct} is the current transformer nameplate primary current rating and I_e is the equipment nameplate current rating.

4) For a multi-ratio internal bushing current transformer with a maximum rating equal to the nameplate rating of the equipment in which it is installed, but which is operating on a reduced tap, the calculated equipment capability should be reduced by the factor

$$\sqrt{I_t / I_n}$$

Where I_t is the reduced tap current rating, and I_n is the maximum current rating of the current transformer.

Information is not readily available on the continuous thermal rating factor of a bushing current transformer, the manufacturer should be consulted.

III. External Bushing Current Transformers –

These are current transformers which use the current-carrying parts of major equipment as their primary windings, and are not usually purchased as integral parts of such equipment. These current transformers are to be assigned ratings by their individual owners, in accordance with the manufacturer's recommendations.

IV. Loading of Secondary Devices –

In all cases where current transformer secondaries may be loaded in excess of 5 amperes, a careful check should be made of the effect this will have on the devices connected in the secondary circuit, with respect to both accuracy and thermal capability.

ATTACHMENT 5

UNITIL ECONOMIC EVALUATION PROCEDURES

Unitil

Economic Evaluation Procedures

Issued: April 24, 2000
Revision 1.0

Unitil

Contents

SECTION I

INTRODUCTION

I.1 General

The following Economic Analysis Procedures provide a standard methodology for the performance of economic evaluations of competing investments. This methodology establishes the minimum evaluation requirements. The analysis results may be used for comparison to other projects within the department and/or to projects in other departments. Individual projects may require additional economic evaluation that is not described in these procedures.

SECTION II

ECONOMIC CRITERIA

II.1 Minimum Revenue Requirements as the Methodology

Economic studies between alternatives will be performed using the Minimum Revenue Requirements (MRR) methodology. This methodology is also referred to as "discounted cash flow", "levelized annual cost", "present value of annual costs", and "present worth". MRR and the other methods establish the time-valued revenue requirements of a project's yearly expenditures over its projected life.[1]

By utilizing the MRR method, Unitil insures that investments are analyzed such that they represent the least revenue required of customers and the lowest cost to the Company.

[1] Revenue requirements are defined as the revenue required to recover the cost of an investment over its lifetime.

II.2 Study Period

The evaluation process requires that each alternative is evaluated over the same time period. Parameters, which distribute the yearly expenditures of a capital project, reflect a time period equivalent to the "book" life [2] of the installed equipment. The evaluation time period (or study period) is defined by the length of time (in years) that the project alternatives are economically compared. Only the revenue requirements associated with the yearly expenditures during the study period will be used in the comparison of alternatives. (for the specific study period criteria see the following section "evaluation criteria").

II.3 Evaluation Criteria

The following guidelines have been established as the economic evaluation criteria.

a. The project with the lowest cumulative present worth of revenue requirements within a 10 year study period will be the preferred alternative. [3]

b. Efficiency type projects (M&O or loss savings) requiring a capital investment will be considered for implementation if the cumulative present worth of the savings fully recovers the cost of the capital project within a 5 year time period.

SECTION III

ECONOMIC STUDY PARAMETERS

III.1 Fixed Charge Rate

The fixed charge rate (i.e. carrying charge rate) is defined as the annual equivalent of all the revenue requirements that are generated by a capital investment. It is expressed as a percentage and is applicable to the projected capital cost of the project under consideration. The fixed charge rate incorporates the following components:

[2] The "book" life represents the time period that an investment is carried on the Company's books. During the "book" life property taxes are paid on the assets and depreciation expenses are applied

[3] A longer study period can be utilized when large investment alternatives such as System Supply additions are being evaluated.

a. MAR Rate - This is the estimated cost of capital to the Company. It is the weighted average of the costs of each class of capital employed by the Company to finance the business.

b. Depreciation Rate - This is the annual sinking fund factor, which would recover the project's initial capital investment less the salvage value.

c. Insurance Rate - This provides for the cost to the Company to establish physical damage insurance coverage.

d. Property Tax Rate - This provides for the estimated property taxes that would be payable over the life of the investment.

e. Income Tax and Business Tax Rate - This provides for recovery of the cost to the Company that is assessed by the Federal and State tax laws. The income tax cost is based on the portion of Company earnings associated with dividend pay-outs to preferred, preference, and common stock holders. The Business tax is based on miscellaneous components.

III.2 Plant and Equipment Cost

Each alternative's plant and equipment cost is the estimated present-day cost of engineering, design, procurement, and installation cost. This cost is developed by the Department performing the evaluation. The costs are escalated for inflation from the present-day estimates to the year they occur.

III.3 Operating and Maintenance Cost

The Operating and Maintenance (O&M) cost will reflect the estimated O&M cost for each alternative or the differential cost between alternative plans. These costs are developed by the Department performing the evaluation. The costs are escalated for inflation from the present-day estimates to the year or years they occur.

III.4 Capital Escalation Rate

The Capital Escalation rate will be used to escalate present-day cost estimates to future year values. The rate provides the allowance for inflation based on estimated changes in the specific price indices.

III.5 Overhead Rates

Overhead Rates will be applied to project costs as required. The overhead rates reflect the portion of the Company's activities that are related to construction and capital projects which are not directly charged to the project. These costs may be excluded from analysis of required projects, if it is deemed that the overhead costs associated with each project are common to all alternatives.

III.6 Energy Loss Costs

The Energy Loss costs shall include both energy and demand charges and shall be evaluated using projected replacement energy market costs.

III.7 Miscellaneous Factors

The following provides a discussion of other factors and their definition. Some of these factors may be included in evaluations as required.

a. AFUDC Costs - The evaluation of alternative plans will not include any adjustments for Allowance for Funds Used During Construction costs (i.e. adjustment for the cost of funds borrowed during construction).

b. Stores Charges - Charges for processing and storing of materials used during the construction process will be allocated to the equipment and materials based upon the current stores allocation rate. It will be applied to the portion of the total cost of materials that are processed through the stock room. This adjustment will be performed when the project cost is estimated.

c. Salvage Value - If the value of retired or replaced equipment substantially exceeds the allocated salvage value in the appropriate plant category, this value should be estimated based on current costs, and shown as a credit to the project cost in the year the credit would be realized.

d. Load Growth Rate - This factor will be used to escalate the energy losses to simulate the increased utilization on the transmission/distribution system as system load increases.

e. Load Factor - The electrical system load factor is used to adjust the losses associated with the project calculated at peak load to reflect expected losses over the entire year of operation. This factor may be used directly in the loss formulas or calculated from the system peak demand and system energy usage for the year.

f. Loss Factor - The electrical system loss factor is used to adjust the losses to reflect the additional losses created on other parts of the electrical system as a result of the energy lost at the point of consideration. A formula is used to calculate this as per a Westinghouse document (Reference #1).

Unitil

IV. Responsibility Chart for Economic Analysis Factors

Common Factors -Developed annually for evaluations performed that year

Name	Frequency	Department Responsible for Developing
Fixed Charge Rate		
MAR (interest rate)	Annually	Finance Department
Depreciation Rate	Annually	Finance/Accounting Department
Insurance Rate	Annually	Finance Department
Property Tax Rate	Annually	Finance/Accounting Department
Income Tax Rate	Annually	Finance/Accounting Department
Replacement Energy Charge	Annually	Energy Contracts Department
Replacement Demand Charge	Annually	Energy Contracts Department
Energy Escalation Rate	Annually	Energy Contracts Department
Project Cost Escalation Rate	Annually	Finance Department
Overhead Rate	Annually	Finance/Accounting Department
Stores Charge	Annually	Finance/Accounting Department
Load Factor *	Annually	Engineering Department
Load Growth Rate *	Annually	Engineering Department

*This Factor may be developed specifically for the project in question as needed.

Specific Factors - these inputs are developed specifically for the project in question.

Name	Frequency	Responsible Department
Plant and Equipment Cost	As needed	Evaluating Department
Operating and Maintenance Cost	As needed	Evaluating Department
Salvage Value	As needed	Evaluating Department
Resistive Losses on Peak	As needed	Engineering Department
Reactive Losses on Peak	As needed	Engineering Department

V. Economic Analysis Formulas - For Reference

Capital Cost = (Plant and Equipment Cost + (P&E Cost Stored * Stores Charge)) * (1 + Overhead Rate)

Capital Annual Revenue Requirements = Capital Cost * Fixed Charge Rate

Load Factor = System Yearly Energy Usage / (System Peak Demand * 8760 hrs)

Transmission System Loss Factor = 0.30*(Load Factor) + 0.70*(Load Factor)^2

Distribution System Loss Factor = 0.15*(Load Factor) + 0.85*(Load Factor)^2

Energy Loss Cost ($) = (1 + Loss Escalation Rate)^(Year - Base Year) * Growth Rate ^ 2 * Peak Losses * Energy Charge * 8760 * Loss Factor

Demand Loss Cost ($) = (1 + Loss Escalation Rate)^(Year - Base Year) * Growth Rate ^ 2 * Peak Losses * Demand Charge * Responsibility Factor

Responsibility Factor = (1.0 for transmission, 0.7 for distribution)

Present Worth of Single Years Charges = (P / F , interest rate, # of years) * (Capital Annual Revenue Requirements + Operating and Maintenance + Loss Cost)

Levelized Annual Cost = (A / P , interest rate, # of years) * Total Accumulated Present Worth

ATTACHMENT 6

LISTING OF CRITICAL LOADS

SIGNIFICANT CUSTOMER LIST

REDACTED

(NOTE: PLEASE SEE CONFIDENTIAL MATERIAL)

ATTACHMENT 7

LISTING OF SIGNIFICANT IMPROVEMENT PROJECTS

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

As a result of the analyses and FG&E's long-term planning and budgeting process, a number of reliability improvements and infrastructure improvement projects are planned for 2004-2008. Because of FG&E's size, all these projects are significant from a reliability standpoint, so many are listed in spite of their relatively small budget impact.

Projects identified for the years 2005-2008 are in the speculation and planning stages and may change in scope and budget amount prior to commencing the project. Only projects which have a defined project scope have been included in this attachment.

2004 - PLANNED ELECTRIC RELIABILITY IMPROVEMENTS

	DESCRIPTION, LOCATION AND SCOPE OF PROJECT	TOTAL AMOUNT TO BE EXPENDED
1	CIRCUIT 01W04 RE-CONDUCTOR (PHASE 2 of 2): This project will be the second phase of a two phase project and will consist of re-conductoring ~6,000 feet of double circuit overhead line from the intersection of South Street and Electric Avenue to the Summer Street Substation. New 336.4 AA spacer cable with a 0000127 AWA (4/0) messenger will be installed along this route and the existing double circuit conductor and appurtenances will be removed. This project includes a river crossing as well as a railroad crossing. The 01W04 circuit will terminate to the Summer Street 13.8kV bus using the spare 40W3 breaker.	$464,153
2	RECONDUCTOR 08 LINE – SUMMER STREET TO PLEASANT STREET: This project consists of reconductoring approximately 1 mile of 69kV construction from 1/0 ACSR to 556 ACSR. This project is required to alleviate loading concerns for the contingent loss of the 09 Line. This project also includes some structure modifications where the 08 and 09 Lines share a common tower. These towers will be removed and each line with be supported on individual structures. This project is to be completed in conjunction with reconductoring the 09 Line.	$446,645
3	RECONDUCTOR 08 LINE – SUMMER STREET TO PLEASANT STREET: This project consists of reconductoring approximately 1 mile of 69kV construction from 1/0 ACSR to 556 ACSR. This project is required to alleviate loading concerns for the contingent loss of the 09 Line. This project also includes some structure modifications where the 08 and 09 Lines share a common tower. These towers will be removed	$446,645

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

	and each line with be supported on individual structures. This project is to be completed in conjunction with reconductoring the 09 Line.	
4	FLAGG POND S/S CONTROL HOUSE CUTOVER: This project is a carryover for the 2003 budget item. This 2004 project is for the cutovers of the breakers, line and transformer protection schemes, and revenue metering to the new control house, and for the removal of all the old below-grade control cables. The cutovers will not be completed in 2003 because of the delivery schedule of the control house, expected by mid-to-late October, 2003.	$270,444
5	RELIABILITY INFRASTRUCTURE PROJECTS: The following reliability projects have been identified for 2004. (1) Substation Animal Protection - During 2003, there has been an abnormally high occurrence of animal contacts within FG&E substations. This project consists of adding animal protection to two substations. (2) Circuit 22W1, Sawyer Passway Vault - The proposed will install a protective device on an unprotected tap which serves radial load. This project is phase 2 of 5 and is similar to the Rollstone Vault reliability project being completed in 2003. (3) Circuit 39W19 Relcoser Installation – The addition of this recloser will allow an increased amount of fusing to be placed closer to the problem areas which will in turn offer greater fault sectionalizing to minimize outages.	$251,643
6	POLE REPLACEMENT: This project is being done as a result of the inspections Osmose completed in 2003 and years prior. Target poles are the condemned poles identified during the 2003 survey as well as any poles remaining from prior years or identified as needing immediate attention during 2004. This project covers the replacing and changing over of approximately 80 condemned poles.	$237,770
7	010 LINE POLE REPLACEMENT: Eight (8) poles were identified by aerial inspection in 2002 as requiring assessment for replacement. Upon further inspection from the ground the poles were noted to have holes created by woodpeckers . The poles were reinspected in June 2003 and found to be riddled with holes and require replacement in 2004.	$79,373
8	DISTRIBUTION CAPACITOR INSTALLATIONS – 4 LOCATIONS: FG&E load power factor is subject to the guidelines of ISO-NE OP-17 - Load Power Factor Correction and service agreement requirements with National Grid. In both cases, load power factor curves for the ISO-NE Harriman-Central Area issued by the NEPOOL Voltage Task Force (VTF) in October 29, 2002, are used as compliance guidelines. These curves establish a minimum power factor capability of 0.990 (lagging) during peak loads. In 2004 at a system peak design load of 106.9 MW, the estimated net power factor is expected to be approximately 0.986 (lagging) with all existing substation capacitors switched into service and Pinetree Power generation out of service. Installation of 3.6 MVAr of p.f. correction capacitors is recommended to improve capabilities. These additions are expected to provide 0.990 minimum power factor capability through 2005. Four capacitor banks will be installed throughout the 13.8kV distribution system.	$70,541
9	RINDGE ROAD S/S TRANSFORMER LOAD RELIEF: Due to the addition of a new water treatment facility on circuit 35H36 along Rindge Road, Fitchburg, three phase primary will need to be extended approximately 2 overhead sections and the primary voltage will be	$59,355

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

	converted to 13.8kV from the Rindge Road substation up to the intersection of Rindge and Bennett Roads (±47 overhead sections). This conversion will include replacing ±7 polemount transformers of various sizes and one three phase 75kVA padmount transformer. A new 167kVA polemount 7.97:2.4kV stepdown transformer will be installed at the intersection of Rindge and Bennett Roads to provide single phase 2.4kV service to the portions of the circuit beyond this point.	
10	ADD SCADA TO PRINCETON ROAD – CARRYOVER: This project was not completed in 2003. This project will install a new RTU at Princeton Rd. and complete wiring modifications required to install SCADA in order to comply with REMVEC requirements for load shedding and voltage reduction tests. Enhancing the Princeton Rd. installation will permit FG&E to perform requisite voltage reduction and/or load shedding via SCADA and receive the system load data before and after response.	$50,455
11	PROTECTION FOR NEW SUMMER STREET TRANSFORMER: This work was originally part of a project that was carried over. The new protection scheme will tie into the Automatic Transfer Scheme between Sawyer Passway and Summer St. The project consists of installing new transformer protection and control in the Summer St. control house and removing the existing relays and control in walk-in switchgear.	$50,424
12	ELIMINATE 20H4 UNSHIELDED CABLE (PHASE 3 of 4): This is a continuation of the projected started in 2002 to eliminate the unshielded cable out of the Nockege Substation designated as 20H24 which serves into downtown Fitchburg. This portion of the project is being written to eliminate the feed into the ARC building & the old FG&E building. The network is already available in both buildings - only modifications to service at the buildings will be required.	$38,626
13	ADD SCADA TO RIVER STREET – CARRYOVER: This project will install a new RTU at River St and complete wiring modifications required to install SCADA in order to comply with REMVEC requirements for load shedding and voltage reduction tests. Enhancing the Summer St and Sawyer Passway installations will permit FG&E to perform requisite voltage reduction and/or load shedding via SCADA and receive the system load data before and after response.	$34,367
14	CIRCUIT 05H12 LOAD TRANSFER: The project involves the installation of a new bank of (3)-333kVA 7.97:2.4kV stepdown transformers on circuit 40W39 near the intersection of Airport and Bemis Roads. All of the load on circuit 05H12 will be transferred onto this new stepdown bank. This project will also include various fuse changes. Circuit 05H12 will remain in service to serve as a backup source for the proposed 4kV portion of 40W39 along Airport Road.	$22,313

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

2005 - PLANNED ELECTRIC RELIABILITY IMPROVEMENTS

	DESCRIPTION, LOCATION AND SCOPE OF PROJECT	TOTAL AMOUNT TO BE EXPENDED
1	UPRATE EXISTING FLAGG POND SPARE: This project will consist of rebuilding the existing 30/40/50 MVA system spare autotransformer to upgrade the capacity to 60/80/100MVA. This will provide a system spare of equal capacity to the #1 and #2 autotransformers currently in service at Flagg Pond. This capacity is required upon the loss of the #1 or #2 autotransformers at Flagg Pond.	$520,000
2	POLE REPLACEMENT: This project is being done as a result of the inspections Osmose completed in 2004 and years prior. Target poles are the condemned poles identified during the 2004 survey as well as any poles remaining from prior years or identified as needing immediate attention during 2005. This project covers the replacing and changing over of approximately 80 condemned poles.	$360,689
3	RELIABILITY INFRASTRUCTURE PROJECTS: Annual reliability analysis is used to develop reliability infrastructure improvement projects. These projects have not been detailed at this time. However, the budget amount is set based upon historical spending.	$169,799
4	40W38 TO 40W39 CIRCUIT TIE: This project involves improvements to the tie circuit between circuits 40W38 and 40W39 out of Summer Street Substation. The existing circuit tie occurs within a customer's switchgear. This project will create a new circuit tie at a different point on the circuits.	$111,987
5	ADD SCADA TO TWO SUBSTATIONS: This project will install a new RTU at two substations and complete wiring modifications required to install SCADA. Enhancing SCADA throughout the FG&E system will permit FG&E to perform requisite voltage reduction and/or load shedding via SCADA and receive the system load data before and after response.	$106,036
6	ELIMINATE 20H4 UNSHIELDED CABLE (PHASE 4 of 4): This is a continuation of the projected started in 2002 to eliminate the unshielded cable out of the Nockege Substation designated as 20H24 which serves into downtown Fitchburg. This project will consist of installing cable and connecting the Fitchburg Savings Bank to the network (MH 225A-226A).	$51,230

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

2006 - PLANNED ELECTRIC RELIABILITY IMPROVEMENTS

	DESCRIPTION, LOCATION AND SCOPE OF PROJECT	TOTAL AMOUNT TO BE EXPENDED
1	REPLACE 11H10, 11H11 AND 11W11 FEEDER PACK BREAKERS: This project consists of replacing the 11H10, 11H11 & 11W11 feeder pack breakers and DX switches at Canton Street Substation. The scope of this project includes the construction of (2) 13.8kV bays, (2) 4.16kV bays, and all associated protection & control, structures, foundations and site work. Insulation breakdown is suspected from electrical testing.	$499,779
2	RECONFIGURE SUMMER STREET BUS 1: This project is designed to create a sectionalizing point on the existing bus 1 at Summer Street between the breaker positions of the 06 Line to Sawyer Passway and the Summer Street transformer breaker. This project will include the purchase and installation of a new tie breaker and all associated steel truss work, disconnect and bypass switches, foundation, and transmission line work. This project is required mitigate the possibility of a single bus failure causing an outage to approximately 5,000 customers.	$348,959
3	ADD SCADA TO FOUR SUBSTATIONS: This project will install a new RTU at two substations and complete wiring modifications required to install SCADA. Enhancing SCADA throughout the FG&E system will permit FG&E to perform requisite voltage reduction and/or load shedding via SCADA and receive the system load data before and after response.	$321,774
4	RELIABILITY INFRASTRUCTURE PROJECTS: Annual reliability analysis is used to develop reliability infrastructure improvement projects. These projects have not been detailed at this time. However, the budget amount is set based upon historical spending.	$156,615
5	POLE REPLACEMENT: This project is being done as a result of the inspections Osmose completed in 2005 and years prior. Target poles are the condemned poles identified during the 2005 survey as well as any poles remaining from prior years or identified as needing immediate attention during 2006. This project covers the replacing and changing over of approximately 20 condemned poles.	$149,297
6	PLEASANT STREET SUBSTATION LOAD RELIEF: This project consists of creating a new circuit tie and changing the open point between circuits 31W38 and 30W31.	$20,565

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

2007 - PLANNED ELECTRIC RELIABILITY IMPROVEMENTS

	DESCRIPTION, LOCATION AND SCOPE OF PROJECT	TOTAL AMOUNT TO BE EXPENDED
1	NEW CIRCUIT FRO WEST TOWNSEND SUBSTATION: This project will consist of installing a new circuit position from West Townsend substation approximately 8 miles. This new circuit will be used to offload Pleasant Street substation transformer by using the spare transformer capacity from West Townsend substation. There is another project for the substation work associated with this project.	$1,919,306
2	FLAGG POND HIGH SPEED RELAYING: FG&E is assuming that the NPCC is going to put forth a regulation which will require the installation of high speed relaying at Flagg Pond.	$299,407
3	UNDERGROUND IMPROVEMENTS: This project is still in the conceptual stages. The FG&E downtown underground system has some cable which was installed in the 1920's. This PILC cable has been prone to outages in the past. This project will begin to replace this cable in an effort to mitigate the opportunity for outages.	$266,881
4	WEST TOWNSEND NEW CIRCUIT POSITION: This project involves the construction of a new 13.8kV breaker position and includes all associated structural, foundation, protection & control and site work. This project is required in conjunction with the new circuit from West Townsend Substation.	$145,426
5	RELIABILITY INFRASTRUCTURE PROJECTS: Annual reliability analysis is used to develop reliability infrastructure improvement projects. These projects have not been detailed at this time. However, the budget amount is set based upon historical spending.	$136,872
6	ADD SCADA TO TWO SUBSTATIONS: This project will install a new RTU at two substations and complete wiring modifications required to install SCADA. Enhancing SCADA throughout the FG&E system will permit FG&E to perform requisite voltage reduction and/or load shedding via SCADA and receive the system load data before and after response.	$145,196
7	POLE REPLACEMENT: This project is being done as a result of the inspections Osmose completed in 2006 and years prior. Target poles are the condemned poles identified during the 2006 survey as well as any poles remaining from prior years or identified as needing immediate attention during 2007. This project covers the replacing and changing over of approximately 20 condemned poles.	$138,573

ATTACHMENT 7

LISTING OF SIGNIFICANT RELIABILITY IMPROVEMENT AND INFRASTRUCTURE IMPROVEMENT PROJECTS

2008 - PLANNED ELECTRIC RELIABILITY IMPROVEMENTS

	DESCRIPTION, LOCATION AND SCOPE OF PROJECT	TOTAL AMOUNT TO BE EXPENDED
1	NEW SYSTEM SUPPLY (PHASE I): The FG&E system is approaching the need for a new system supply. The existing system supply is currently at approximately 93% of the equipment rating and is projected to surpass the equipment ratings within the next ten years. This project is still under the conceptual stages and represents half of the estimated project price.	$3,001,579
2	UNDERGROUND IMPROVEMENTS: This project is still in the conceptual stages. The FG&E downtown underground system has some cable which was installed in the 1920's. This PILC cable has been prone to outages in the past. This project will begin to replace this cable in an effort to mitigate the opportunity for outages.	$269,036
3	POLE REPLACEMENT: This project is being done as a result of the inspections Osmose completed in 2007 and years prior. Target poles are the condemned poles identified during the 2007 survey as well as any poles remaining from prior years or identified as needing immediate attention during 2008. This project covers the replacing and changing over of approximately 20 condemned poles.	$141,594
4	RELIABILITY INFRASTRUCTURE PROJECTS: Annual reliability analysis is used to develop reliability infrastructure improvement projects. These projects have not been detailed at this time. However, the budget amount is set based upon historical spending.	$131,217
5	MISC SCADA ENHANCEMENTS: This project will install a new RTU at two substations and complete wiring modifications required to install SCADA. Enhancing SCADA throughout the FG&E system will permit FG&E to perform requisite voltage reduction and/or load shedding via SCADA and receive the system load data before and after response.	$19,682

ATTACHMENT 8

PROJECT PRIORITIZATION GUIDELINES

Project Prioritization Guidelines:

FG&E practices uniform procedures for prioritizing capital projects. The following is the expectations of these guidelines:

1. Provide basic information on the proper categorization and prioritization of capital projects to ensure accurate and consistent entry to the budget system.
2. Define expectations for the proper development and justification of capital projects to ensure that individual budget items are well defined, well estimated and well justified.

All justifications must have a priority assigned prior to submission. These priorities are to be assigned (by the budgeter) to all items in the Capital budget.

Priority 1

Absolutely essential for the Company to distribute and receive payment for gas and electricity.

- Construction required to serve new customer load.
- Construction to address critical constraints such as load, voltage and pressure where they jeopardize the Company's ability to distribute gas or electricity.
- Construction to restore service during storms and emergencies.

Budget categories typically assigned a priority 1.

- Transmission, distribution and substation specific projects to address load, pressure, voltage or protection constraints.
- Line Extensions and Mains Extensions, customer driven specific projects.
- Blankets for New Customer Additions, Outdoor Lighting, Emergency & Storm Restoration, Billable Work, Transformers, Meters, New Gas Services, Water Heater & Burner Replacements, and Meter Purchase & Installation.

Priority 2

Essential for direct support of priority #1. Necessary to perform assigned business functions in required manner including regulatory or legal requirements, intercompany operating agreements, and related facilities, fleet and equipment infrastructure.

- Construction which is not load driven or customer driven, but which is requested by state or local government, other utilities in accordance with IOP's, etc.
- Construction required to meet or address legal and regulatory requirements.
- Facilities, tools and infrastructure required to perform essential functions.

Budget categories typically assigned a priority 2.

- Telephone company requests, highway relocations, joint encapsulation, cast iron replacement.

- Blankets for T&D System Improvements, Gas Distribution System Improvements, Corrosion Control, and Abandoned Services.
- Fleet replacement in accordance with established Company guidelines.
- Tools and equipment required to support essential Company requirements.
- Upkeep of structures and facilities required to meet essential Company requirements.

Priority 3

Any project not falling into either Prority 1 or Priority 2 will be assigned a Priority 3. In general, any such project will be considered an improvement or enhancement to existing systems or capabilities, and will be deemed discretionary. The "test" of whether a project is essential or discretionary will rely on a determination that the project is (or is not) absolutely essential to distribute and receive payment for gas and electricity, or is (is not) essential to meet business and regulatory obligations.

- System reliability projects and improvements.
- Projects with a defined economic payback.
- Projects which improve or enhance gas or electric system capabilities.
- Replacement of old or obsolete equipment where such replacement is not the result of failure, and does not prevent the Company from adequately distributing gas or electricity.
- Maintaining or initiating desirable projects and programs.

Upon completion of the capital budget process, the Priority 1 and Priority 2 projects will constitute a base budget of critical/essential funding to meet ongoing business obligations. Priority 3 projects will be ranked according to merit and funded in accordance with Company goals, priorities, available resources and funds.